BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East
Suite 350
St. Paul, Minnesota 55101-2147

MPUC Docket No. E015/GR-16-664
OAH Docket No. 5-2500-34078

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota

DIRECT TESTIMONY AND SCHEDULES OF MINNESOTA OFFICE OF THE ATTORNEY GENERAL – RESIDENTIAL UTILITIES AND ANTITRUST DIVISION

WITNESS:

SHOUA LEE

May 31, 2017

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I. BACKGROUND AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Shoua Lee. My business address is 445 Minnesota Street, Suite 1400, Saint Paul, MN 55101.

Q. By whom are you employed?

A. I am a Financial Analyst with the Residential Utilities and Antitrust Division in the Office of the Minnesota Attorney General ("OAG").

Q. What is your educational and professional background?

A. I have a Master of Business Administration and a Bachelor of Science in Finance. I have provided testimony on behalf of the OAG in the following general rate cases; Otter Tail Power's electric rate case in Docket No. E-017/GR-15-1033, Xcel Energy's electric rate case in Docket No. E-002/GR-15-826, CenterPoint Energy's gas rate case in Docket No. G-008/GR-15-424, and Dakota Electric Association's electric rate case in Docket No. E-111/GR-14-482. I have also provided analysis in other utility rate cases, depreciation filings, rider filings, as well as other financial dockets.

II. PURPOSE

Q. What is the purpose and scope of your testimony?

A. The purpose of my testimony is to review Minnesota Power's ("the Company" or "MP") request for a rate increase, and evaluate whether specific portions of that request are reasonable. In general, I focus on evaluating the Company's revenue deficiency, including its claimed costs and revenues. Following my evaluation, I recommend several specific changes. I do not, however, provide an opinion on the overall revenue

requirement or revenue deficiency. Instead, I recommend specific changes that should be made, and do not have a recommendation on those issues on which I did not provide testimony.

III. TRANSMISSION CAPITAL ADDITIONS

Q. Does the Company summarize its transmission capital additions for the 2017 Test Year?

A. Yes. The Company provided its actual 2010 to 2015 transmission capital additions, as well as its forecasted 2016 transmission capital additions, and budgeted 2017 capital additions in MP Exhibit_(CEF) Direct Schedule 1.

Q. How are these forecasts related to the 2017 Test Year?

A. A Test Year has a beginning-of-year rate base and an end-of-year rate base because capital additions occur during the year. To ensure that these additions are reflected, but not double-counted, rates are set on an average basis. In other words, the rate base number that is used to construct the revenue requirement is the beginning-of-year rate base plus the end-of-year rate base divided by two. The 2017 beginning-of-year rate base is based on 2016 numbers, and the 2017 end-of-year rate base reflects the capital additions included in the Test Year. At the time the Company filed this case using a 2017 Test Year, however, it did not have final 2016 numbers. For that reason, the Company used forecasted 2016 numbers to construct the 2017 beginning-of-year rate base in the Test Year.

Q. Does the Company have the actual 2016 amount of transmission capital additions?

A. Yes. The Company responded to the Department of Commerce's ("Decpartment") Information Request to update MP Exhibit_(CEF) Direct Schedule 1 with actual 2016 amounts.[1]

Q. Is the actual 2016 amount different than the Company's forecast?

A. Yes. The actual 2016 amount of transmission capital additions is less than the Company's 2016 forecast by $16.4 million. This decreases the Company's in-service plant balance by $16.4 million for 2016 and has a carry forward impact to the 2017 Test Year beginning balance for in-service plant that is used to calculate the rate base and revenue requirement. The impact of this decrease lowers the 2017 Test Year revenue requirement by $1,604,396.[2]

Q. What is your recommendation?

A. I recommend that the Company update its 2016 in-service plant ending balance and subsequent 2017 in-service plant beginning balance, in order to reflect the decreased levels of in-service plant in the 2017 Test Year, and to decrease the revenue requirement by $1,604,396.

Q. Do you have other concerns about this issue?

A. Yes. The Company stated in its response to the Department's Information Request that in calculating the impact of the $16.4 million decrease in in-service plant on the 2017 Test Year revenue requirement, it "assumed that all delayed 2016 projects are completed in 2017."[3] I interpret this statement as meaning that the Company has assumed that all of

[1] *See* Department Information Request 2105, Schedule SL-1.
[2] *Id.*
[3] *Id.*

the 2016 projects that were not completed will be completed in 2017. I am concerned that this one-line statement in an Information Request is the only evidence the Company has provided to substantiate its assumption that it will complete all 2016 delayed projects by the end of the 2017 Test Year. I am also concerned because it appears that the Company is also assuming that completing the 2016 delayed projects will have no impact on the budget available for 2017 projects, or that adding the 2016 projects will have no impact on the budget available for 2017 projects. I do not think this makes sense. It is reasonable to assume that the Company's 2017 budgeted capital projects will change if it is now choosing to focus its resources and project timelines to completing delayed 2016 projects rather than on focusing on its budgeted 2017 projects.

Q. How will you address this issue?

A. I do not have a recommendation at this time, but ask that the Company provide more information on the impact that delayed 2016 capital projects has on planned projects for 2017.

IV. GENERATION CAPITAL ADDITIONS

Q. Does the Company summarize its generation capital additions for the 2017 Test Year?

A. Yes. The Company's budgeted generation capital additions of $27.7 million in the Test Year as shown in MP Exhibit _(JJS) Direct Schedule 1. These additions represent the difference between the beginning-of-year generation capital rate base, and the end-of-year generation capital rate base. At the time it filed its rate case, MP projected that it would add $27.7 million of generation capital investments during the Test Year.

Q. Did the Company update its 2017 generation capital additions?

A. Yes. I issued a discovery request that asked the Company to update MP Exhibit_(JJS) Direct Schedule 1. The Company's response indicated that the in-service dates have changed for seven of the generation capital projects, such that these seven projects will either no longer be in service in 2017, or have been postponed or cancelled.[4] The Company also stated that five other projects now have different in-service dates within the 2017 Test Year, where four of these five projects had in-service dates that were delayed between one to two months.

Q. What were the 2017 budgeted amounts for those projects that have a new in-service date outside of the 2017 Test Year?

A. The seven generation capital projects that will not be in service in the 2017 Test Year total $2.3 million.

Q. Did the Company request to substitute these seven projects with other capital projects?

A. Yes. The Company stated there are six new generation capital projects that have "emerged after the creation of the Test Year project." The Company states these six new projects will have in-service dates in the middle and end of 2017.

Q. Do you have concerns about this substitution?

A. Yes. My primary concern is that the Company has provided no information about this substitution other than this very brief statement. I do not view this as sufficient to include new projects in the Test Year.

[4] *See* OAG Information Request 124, Schedule SL-2.

Q. What is your recommendation?

A. I recommend the Company remove $2,303,091 which is the 2017 budget for the generation capital projects that will not be in-service in the 2017 Test Year, which will impact the 2017 Test Year revenue requirement. I have asked the Company to provide the impact on the revenue requirement of taking these projects out of the Test Year in OAG Information Request 155 and will provide this amount in my rebuttal testimony.

V. DEPRECIATION FOR THE BOSWELL ENERGY CENTER

Q. What is the Boswell Energy Center?

A. The Boswell Energy Center ("BEC") is a group of coal-fired electrical generating units owned by MP and located in Cohasset. The BEC is made up of four generating units—BEC 1, 2, 3, and 4. BEC 1 and 2 are older units with a net generating capability of 67 MW each.[5] BEC 3 is a newer and larger facility that provides a capacity of 364 MW.[6] BEC 4 is the newest and largest generator, with a nameplate capacity of 585 MW.[7] Together, the four generators provide more than 1,000 MW of generating capacity. The BEC also includes the Common Facilities, made up of equipment and other investments that are shared by the various generating units.

Q. Does MP have a proposal related to the BEC in this case?

A. Yes. MP proposes to make significant changes to the depreciation rates for the BEC investments. The Company's proposal is, essentially, made up of two parts. First, MP proposes to combine the five separate investments of the BEC into a single investment

[5] Skelton Direct at 19.
[6] *Id.* at 18.
[7] *Id.* at 13.

for purposes of depreciation. And, second, MP proposes to significantly extend the depreciation schedule of the BEC investments to 2050.

Q. What is depreciation?

A. Depreciation represents the reduction in value of an investment over time. Once an investment, such as a coal-fired generating plant, is made, it immediately begins to reduce in plant value. Over time its value, which is recorded as rate base on the Company's books, is reduced to zero. Normally, an investment is depreciated evenly over the useful life of the investment which results in a depreciation schedule that is intended to reach a plant balance of $0 at the time the investment is expected to be retired or removed. Utilities make annual filings with the Minnesota Public Utilities Commission ("Commission" or "MPUC") to determine depreciation rates for their rate base investments.

Mechanically, depreciation affects rates in two ways. First, the plant values of in-service investments are reduced. This has the impact of the reducing the rate base value on which a utility earns a rate of return. Second, the amount of depreciation expense in the Test Year is recorded as an operating expense to the utility and, like other types of operating expenses, increases the revenue requirement.

In addition to the reduction of value in investments, depreciation expense includes removal expenses. In general, utilities are expected to incur additional expenses to remove or shut down investments like power plants at the time they are retired. To ensure that sufficient funds are available at the time of retirement, utilities estimate the removal funds that will be needed in the future and recover them over the same schedule that is used for depreciation expense.

Q. What is the current depreciation schedule for the BEC investments?

A. The Commission's most recent order regarding the depreciation schedule for the BEC came in the Company's 2016 Remaining Life Depreciation Petition. In that Petition, MP contemplated one change for the BEC investments from the Commission's decision in its 2015 Integrated Resource Planning ("IRP") filing,[8] which was to adjust the remaining life for BEC 1 and 2 from 2022 to reflect a possible shut down of these two units on December 31, 2018.[9] The Department comments in the depreciation filing supported the shutdown of BEC 1 and 2 by the end of December 2018. The Company agreed with the Department's recommendation and the Commission approved this proposal.[10] Based on this decision, the useful lives of BEC 1 and 2 will end in 2018; BEC 3 in 2034; BEC 4 in 2035; and the Common Facilities on 2030. The remaining life of BEC Common is based on an average of the other units.

Q. What is the basis for the current depreciation schedule for BEC?

A. The current schedule for BEC depreciation is based on the Company's estimate for when the physical life of the units will end. In other words, it is based on the Company's estimate of when the units will be retired or decommissioned.

Q. Does MP propose to change the expected operational lives of the BEC investments?

A. No. After several rounds of discovery I still felt that MP's request was somewhat unclear, so I issued OAG Information Request No. 127, which asked the Company to "confirm that MP's proposal is to separate the 'cost recovery' period for depreciation

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[8] *In the Matter of Minnesota Power's 2016-2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS, at 15 (July 18, 2016).

[9] *In the Matter of Minnesota Power's 2016 Remaining Life Depreciation Petition*, Docket No. E-015/D-16-797, 2016 REMAINING LIFE DEPRECIATION PETITION, at 12 (Sept. 30, 2016).

[10] *In the Matter of Minnesota Power's 2016 Remaining Life Depreciation Petition*, Docket No. E-015/D-16-797, ORDER (Apr. 21, 2017).

expense for the BEC Units . . . from the operational or physical life period," or, in the alternative to confirm if the Company was "proposing that the operational or probable service life of any of the BEC Units be extended to 2050."[11]

MP responded:

> **Yes, Minnesota Power's proposal is to separate the cost recovery period for depreciation expense for the BEC units from the operational life of these units**. . . . While the Direct Testimony of Company witness Mr. Herbert G. Minke, III asserts that BEC units may physically be operated until 2050, the Company is not proposing any changes to the operational or probable service lives of BEC units as part of this rate review proceeding. We expect discussions about the future operations of BEC units to be made in other regulatory proceedings, such as future Integrated Resource Planning dockets."[12]

This response confirms my understanding that MP's proposal is to separate the cost recovery schedule for depreciation expense from the operational life of the BEC units. In other words, the depreciation schedule would no longer be based on the remaining life of the BEC units.

Q. Is MP's proposal consistent with standard accounting rules?

A. No. As MP's witness Mr. Minke explained, utilities in Minnesota are required to follow FERC's Uniform System of Accounts ("USoA").[13] Mr. Minke explained that the USoA "states that utilities must use a method of depreciation that allocates, in a systemic and rational manner, the service value of depreciable property over the service life of the property. It also states that the estimated useful service lives of depreciable property

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[11] OAG Information Request No. 127, Schedule SL-3.
[12] *Id.*
[13] Minke Direct at 20; Minn. Rules part 7825.0300, subp. 2.

must be supported by engineering, economic, or other depreciation studies."[14] Mr. Minke suggests that GAAP would treat depreciation in a similar manner.[15]

The Commission's Rules are consistent with this understanding. According to Minnesota Rules part 7825.0500, subpart 7, "'Depreciation accounting' means a system of accounting which aims to distribute costs or other basic value of tangible capital assets, less salvage, if any, over the estimated useful life of the unit . . . in a systematic and rational manner." The Rules also require that utilities use the "straight-line method" for depreciation, which is a plan where "the original cost of an asset adjusted for net salvage is charged to operating expenses . . . through equal annual charges over its probable service life."[16] The Rules further state that "[a]ny exception to these methods will require specific justification and certification by the commission."[17]

It appears to me that MP's proposal to separate the cost recovery of depreciation expense for BEC from the operational life of BEC would not be consistent with the depreciation procedures laid out in the Commission's rules. It is my understanding that the Commission typically applies a three-part test when it is asked to vary its rules.[18] It does not appear that MP has requested a variance in this rate case proceeding, or attempted to satisfy the three parts that are required for a variance.

[14] Minke Direct at 21.
[15] *Id.*
[16] Minn. Rules part 7825.0500, subp. 14; Minn. Rules part 7825.0800.
[17] Minn. Rules part 7825.0800.
[18] *See* Minn. Rules part 7829.3200.

Q. If MP's proposal does not follow the USoA or the Commission's Rules, how does the Company support its proposal?

A. Mr. Minke suggests that the Commission has the authority to "deviate from standard FERC accounting when determining the remaining service life or recovery period of an asset."[19] By doing so, Mr. Minke asserts, the Commission can establish new GAAP for depreciation expense.[20] I take no position on whether Mr. Minke's assertions are correct. I note, though, that Mr. Minke does not provide any citations to law, rule, or decisions of the Commission, to support his claim. And, as I noted above, it does not appear that MP has addressed the requirements that are used to obtain a variance from the Commission's Rules.[21]

I note my concerns regarding variance and legal requirements to ensure that MP has an opportunity to address them if the Company wishes. The rest of my testimony, however, will focus on whether the Company's proposal is reasonable.

Q. Do you believe that MP's proposal is reasonable?

A. No, I do not. There are multiple problems with the proposal, which I will explain in more detail. Because the different BEC units are under relatively distinct situations, I will discuss BEC 1 and 2 separately from BEC 3 and 4. I will begin with BEC 3 and 4 because they have the largest remaining plant balance.

[19] Minke Direct at 21.
[20] *Id.*
[21] *See* Minn. Rules part 7829.3200.

A. BEC 3 AND 4.

Q. What is the status of BEC 3 and 4?

A. BEC 3 and 4 are much larger and newer generators than BEC 1 and 2. MP has recently completed significant emissions upgrades on both units.

Q. What is the current remaining life of BEC 3 and 4?

A. As I discussed above, the most recently approved depreciation schedule for BEC 3 and 4 is based on an estimated remaining life that would end in 2034 and 2035, respectively. Under normal circumstances, this would indicate that the depreciation schedules for which depreciation expense is charged and collected from ratepayers would follow the operational life of BEC 3 and 4 and would end in 2034 and 2035.

Q. When does MP plan to retire BEC 3 and 4?

A. Retirement decisions for these generating units are normally handled in the Company's IRP proceedings. MP's most recent IRP proceeding covered the years of 2016 – 2030 – the remaining lives of BEC 3 and 4 were outside of the planning period, so there was not significant discussion regarding MP's plans in the IRP. I attempted to learn MP's long-term plans for BEC 3 and 4 through discovery. In OAG Information Request No. 907, I asked the Company to share its current plan for retirement of BEC 3 and 4.[22] The Company responded that it "has not made any plans for the future retirement of BEC 3 and 4," and noted that it would discuss its plans as part of future IRP proceedings.

Q. What is MP's proposal regarding BEC 3 and 4 in this case?

A. The Company proposes to keep the retirement dates for BEC 3 and 4 as the end of 2034 and 2035, but to extend the depreciation schedule for charging depreciation expenses for

[22] OAG Information Request 907, Schedule SL-4.

BEC 3 and 4 to 2050. In other words, the Company is requesting to "separate the cost recovery period for depreciation expense for the BEC units from the operational life of these units."[23]

Q. Do you agree with MP's depreciation proposal for BEC 3 and 4?

A. No, I do not. I have five specific concerns with the Company's proposal for BEC 3 and 4. They are related to 1) stranded costs; 2) removal expenses; 3) uncertainty of future O&M or replacement; 4) increased long-run returns for shareholders; and 5) delay of coal retirements. I will address each of these concerns in turn.

1. Stranded Costs.

Q. What are stranded costs?

A. Stranded costs are the costs of capital investments that are left over when a generating facility (or other kind of investment) is retired before it is fully depreciated. Under normal utility ratemaking standards, stranded costs are not recoverable because utilities are allowed to recover the costs of capital investments *only* when those investments are "used and useful." Stranded costs are not normally recoverable because they come from retired plants that are not currently used and useful.

Q. Can you provide an example of stranded costs?

A. Yes. To provide a simple example, imagine a coal plant with a rate base balance of $100 and a straight-line depreciation schedule of 50 years. The plant would depreciate by $2 each year. If the plant is retired after 25 years (rather than the 50 that were originally estimated), the plant will have a remaining, undepreciated rate base balance of $50 when it is retired. This $50 in plant value is "stranded," because it was not recovered before

[23] OAG Information Request No. 127, Schedule SL-3.

the plant was retired. Under normal utility ratemaking standards, the $50 in stranded costs would not be recovered, because the investment in question is not used and useful.

Q. How is MP's proposal related to stranded costs?

A. If approved, MP's proposal would provide the Company with a mechanism to recover any current and future costs of BEC 3 and 4 that would have been stranded costs, had the Company not been able to recover those costs before the end of the units' useful lives. The Company is proposing to separate the depreciation schedule of BEC 3 and 4 from its operational life. In other words, the operational life of BEC 3 and 4 would end in 2034 and 2035 based on current estimates, but the depreciation expense for all current and future costs would still continue to be charge to ratepayers and recovered by MP until 2050. That means that the plants would not be fully depreciated at the end of their operational lives, and ratepayers would continue to pay for the units for many years after they are expected to be retired and no longer used and useful.

Q. What are the problems with stranded costs?

A. There are two primary problems with allowing utilities to recover stranded costs. First, it goes against many decades of traditional ratemaking principles. Normally, utilities are only permitted to recover the costs of investments that are used and useful. Ratepayers are required to pay for things that are currently being used to provide utility service. Stranded costs, in contrast, are no longer providing benefits to ratepayers. When ratepayers are paying stranded costs, they are paying for investments that are no longer in operation and are not providing a benefit to anyone.

The second problem is related to intergenerational inequity. Normally, the Commission seeks to tie costs to ratepayers at the time those costs are necessary. In other

words, ratepayers in 2017 should be paying for the costs required to provide service in 2017. MP's proposal would upend this standard. Under the Company's proposal, ratepayers in 2049 would still be paying for coal plants that are expected to be closed more than a decade earlier. Intergenerational inequities such as this are inherently unfair—ratepayers in 2049 should be paying for the costs necessary to provide utility service in 2049, not for plants that have been closed for more than a decade.

Q. Has any other utility ever recommended the creation of stranded costs?

A. No. However, MP requested a somewhat similar treatment for the Sappi/Cloquet Generator Number 5. The generator is located at a customer facility, and the customer, Sappi, used to own parts of the facility with MP. As part of the initial agreement between Sappi and MP, Sappi had the right to purchase the Sappi/Cloquet generator in 2016, which it did.[24]

In its 2015 Depreciation Petition, MP asked to be allowed to continue to depreciate the Sappi/Cloquet generator until 2024, even though it would no longer own the generator starting in 2016. The Department recommended that "a reasonable remaining life for S/C5 for depreciation purposes is one that matches the expected operational life," and recommended a two year depreciation so that the facility would be fully depreciated at the time ownership was transferred to Sappi.[25] The Commission

[24] *In the Matter of Minnesota Power's 2015 Remaining Life Depreciation Petition*, Docket No. E-015/D-15-711, ORDER APPROVING REMAINING LIVES AND SALVAGE RATES AS MODIFIED, AND REQUIRING FILINGS at 5 (Sept. 19, 2016).

[25] *In the Matter of Minnesota Power's 2015 Remaining Life Depreciation Petition*, Docket No. E-015/D-15-711, COMMENTS OF THE DEPARTMENT, at 5 (Oct. 30, 2015).

agreed with the Department, and stated that "it would not be reasonable to allow [MP] to depreciate an asset it no longer owns."[26]

Following this decision, MP requested permission for deferred accounting related to the incremental depreciation expense it had to charge for the Sappi/Cloquet generator due to the acceleration of the generator's useful life (from 2024 to 2016).[27] This incremental depreciation expense represented stranded costs because while MP incurred the increased depreciation expense, the depreciation expense being recovered from ratepayers at the time was based on a useful life of 2024. The usual recovery mechanism for depreciation expense is through base rates in a general rate case, and the Company would have had to request recovery of the increased depreciation through a general rate case proceeding. However, MP choose to file the deferred accounting request instead. The Department recommended denial of MP's deferred accounting request,[28] and the Company withdrew its Petition before the Commission reached a decision.[29]

Q. Has the Commission ever authorized the recovery of stranded costs?

A. I do not believe so. In OAG Information Request No. 908, I asked MP whether the Commission had ever approved the recovery of stranded costs. The Company responded that it had "not done an exhaustive search, but is currently not aware of any MPUC

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[26], *In the Matter of Minnesota Power's 2015 Remaining Life Depreciation Petition*, Docket No. E-015/D-15-711, ORDER APPROVING REMAINING LIVES AND SALVAGE RATES AS MODIFIED, AND REQUIRING FILINGS at 6 (Sept. 19, 2016).

[27] *In the Matter of a Petition for Approval of Deferred Accounting Treatment of Costs Related to Depreciation Expenses for Sappi-Cloquet Generator No. 5*, Docket No. E-015/M-16-876, PETITION (Oct. 28, 2016).

[28] Petition, *In the Matter of a Petition for Approval of Deferred Accounting Treatment of Costs Related to Depreciation Expenses for Sappi-Cloquet Generator No. 5*, Docket No. E-015/M-16-876, COMMENTS OF THE DEPARTMENT (No. 28, 2016).

[29] *In the Matter of a Petition for Approval of Deferred Accounting Treatment of Costs Related to Depreciation Expenses for Sappi-Cloquet Generator No. 5*, Docket No. E-015/M-16-876, REQUEST TO WITHDRAW PETITION (Oct. Dec. 20, 2016).

orders that have authorized recovery of costs for electric generation units after their retirement."[30]

Q. Does the Commission have the authority to deny recovery of stranded costs?

A. Yes. Minnesota law allows utilities to request the recovery of stranded costs under certain conditions. But the same law also makes clear that the decision as to whether the costs should be recovered is left to the discretion of the Commission.

Minnesota Statutes section 216B.16, subdivision 6 provides that "[i]f the [C]ommission orders a generating facility to terminate its operations before the end of the facility's physical life in order to comply with a specific state or federal energy statute or policy, the [C]ommission *may* allow the public utility to recover any positive net book value of the facility as determined by the [C]ommission." This statute makes it possible for utilities to recover stranded costs, but does not require it. Instead, the statute requires the Commission to decide on a case by case basis whether the recovery of stranded costs would lead to just and reasonable rates. If not, then the Commission should deny that recovery.

Q. Does the Commission have any other authority regarding stranded costs?

A. Yes, the Commission also has the authority to make regulatory decisions that will avoid stranded cost problems in the first case. For example, rejecting MP's proposal in this case would avoid a stranded cost problem in the future.

Q. What is your conclusion regarding stranded costs?

A. I believe that this is a significant problem with MP's proposal. I do not believe that it would be reasonable to approve this proposal which appears likely to create a mechanism

[30] OAG Information Request No. 908, Schedule SL-5.

by which MP would be able to recover potential future costs that would be stranded costs once BEC 3 and 4 are expected to be retired at the end of 2034 and 2035. This would limit the Commission's future ability to review and decide on a case by case basis whether recovery of those future costs would lead to just and reasonable rates.

2. Removal Costs.

Q. How are removal costs related to depreciation schedules?

A. As I discussed above, when utilities charge depreciation expense for a capital investment, a piece of the depreciation expense is related to the removal costs. The amount of removal costs charged to ratepayers and accumulated each year is based on two things: the estimated cost of removing the investment after retirement, and the operational life of the investment. Normally this removal cost is charged to ratepayers along with the service value of depreciable property under the same depreciation schedule—over the service life of the property. This results in the same amount of removal dollars being charged to ratepayers each year for the remaining life of the investment, so that the entire estimated removal costs are accumulated by the end of the investment's operational life.

Q. Can you provide an example?

A. Yes. Imagine that a coal plant has an operational life of 50 years, with an expected removal cost of $50. Each year, the utility will book $1 of removal expense, so that it will have $50 available for removal when it is time to retire the facility.

Q. What is the problem with removal costs for BEC 3 and 4?

A. A problem would arise as a result of MP's proposal to extend the depreciation schedule for the units beyond their estimated operational lives. MP currently estimates that it will

cost approximately $80 million to decommission BEC 3 and 4.[31] MP's proposal is to extend the time period to fully recover the entire $80 million in removal expense by 2050. This means that MP will not have $80 million available for decommissioning until 2050—but the current operational life of the units is expected to end 15 years earlier in 2034 and 2035.

If MP's proposal is approved and BEC 3 and 4 are retired any time earlier than 2050, then MP will not have sufficient removal dollars to fund the decommissioning of the units.

Q. What would happen if MP retired BEC 3 or 4 before it accumulated sufficient removal dollars to fund the decommissioning?

A. It is unclear. The utility would either need to fund the decommissioning itself—which I believe the utility would be unlikely to agree to—or it would need to request accelerated payments from ratepayers at the time of retirement. This is the reason that depreciation schedules and removal expenses are normally targeted to be based on the operational life of the units.

Q. What would happen to removal costs if BEC 3 or 4 were operated beyond 2034 and 2035?

A. This is also somewhat unclear. I asked MP to provide an estimate of the removal costs for BEC 3 and 4 if they were operated past their current operational lives. MP did not have an updated estimate. In fact, it appears that the Company suggests that the cost of

[31] OAG Information Request No. 1158 and OAG Information Request No. 1158.1, Schedule SL-6.

decommissioning BEC 3 and 4 would not change from the current estimate even if the units are operated longer than expected.[32]

The Company's suggestion does not make much sense. Based on my experience, delaying the decommissioning of units tends to increase the removal costs. This is partly related to regular inflation for costs such as construction and labor. I believe it is likely that decommissioning BEC 3 or 4 in 2050 would cost more than it would in 2035. While the depreciation expense for both the removal cost and service value of the units will be recalculated in the future as new estimates become available, the Company's suggestion that the cost will remain the same regardless of when the units are retired simply does not make sense.

Q. What is your conclusion regarding removal costs for BEC 3 and 4?

A. MP's proposal would extend the time period for accumulating dollars for removal costs beyond the expected operational life of the units. This means that the removal dollars necessary to fund decommissioning would likely not be available at the time the facilities are expected to be retired. If the Commission decided to accelerate the retirement of the units, because, for example, it wanted to reduce carbon emissions, the problem could be even greater. I view this as a significant problem with MP's proposal.

3. Estimated O&M And Replacement Costs.

Q. What is your concern regarding future O&M and replacement costs for BEC 3 and 4?

A. One of the justifications MP provides for its proposal is an opinion from the engineering firm Burns & McDonnell stating that the firm "see[s] no technical reasons that BEC

[32] OAG Information Request No. 1159, Schedule SL-7.

could not physically be operated until 2050, with appropriate maintenance and investments into replacements and upgrades."[33]

Even though the Company claims it is not seeking to extend the operational life of BEC 3 and 4, it seems clear that the Company is positioning itself to do so in the future by extending the depreciation schedule for the units until 2050. To the extent that the Company is suggesting that the units could be operated longer than their current operational lives, it is very important that the Commission have accurate information about the costs of doing so. Since the Company hired Burns and McDonnell to evaluate whether the units could be operated until 2050, I assumed that the Company had estimates for the cost of doing so, and had requested them in discovery.

Q. What was MP's estimate of the cost of operating BEC 3 and 4 past their current operational lives?

A. The Company stated that it had no estimates for the cost of operating BEC 3 and 4 past 2034 and 2035. Based on the language in the opinion from Burns & McDonnell, in OAG Information Request No. 1148, I asked the company for all estimates of the "maintenance and investments into replacements and upgrades" that would be required. The Company stated that it "has not conducted an estimate of the costs."[34] The Company pointed out that a major driver in the costs would be "ongoing maintenance and repair of the boilers and turbine-generators for each unit."[35]

[33] Minke Direct, Schedule 10.
[34] OAG Information Request No. 1148, Schedule SL-8.
[35] *Id.*

Q. Did you conduct any additional discovery?

A. I followed up with additional discovery because I did not find it plausible that the Company had no estimate at all, since it appears that MP would be able to request an extension of the operational lives for the units. In OAG Information Request No. 1155, I asked the Company to produce all documents and analysis it had regarding "potential future maintenance," including sensitivity analysis, or to confirm that it had no relevant documents. The Company did not produce any cost estimates, but instead pointed to the analysis included in its most recent IRP proceeding.[36] I do not believe this information is responsive, however, because the planning horizon for the IRP goes from 2016 to 2030. Information about the cost of operating BEC 3 and 4 until 2030 is not a good gauge of how much it might cost to keep the units open until 2050. The only documents the Company provided were technical reports about maintenance work that was required, without any cost estimates included.

I also asked the Company for more information about the potential cost of replacing the boilers and turbines at BEC 3 and 4. I agree with the Company's assessment that replacement or repair of these types of equipment could be a very significant expense. If operating the units until 2040 or 2050 would require the Company to replace this equipment, but retiring the units in 2035 or earlier would not, that is important information that the Commission should be aware of. In response to OAG Information Request No. 1156, MP stated that it had no estimate of the physical life of the boilers and turbines currently installed at BEC 3 and 4, had no information about the lifespan of similar equipment at other facilities nationwide, had no information about

[36] OAG Information Request No. 1155, Schedule SL-9.

manufacturer representations or warranties regarding the lifespan, and had no estimate of the cost of replacing this type of equipment at similar facilities.[37]

I also asked for more information about the estimated O&M costs from 2016 to 2050. In response to OAG Information Request No. 1157, the Company stated that it did not have a detailed cost estimate.[38]

Q. What do you conclude about estimates of future cost at BEC?

A. It appears that MP has no idea how much it would cost to operate BEC 3 or 4 past their current operational lives. I find this very concerning, given that the Company hired an engineering firm to give an opinion on whether doing so was feasible, and then used that opinion to justify its proposal to extend the depreciation schedule of BEC 3 and 4.

The Company may not be asking to extend the operational life of the units now, but the Company seems to believe that whether or not the units could remain functional until 2050 is relevant to its request. This means that the cost of remaining functional is also relevant to the depreciation schedule issue, and I find it concerning that the Company has no estimate of those costs.

It is possible that the Company will take the position that I did not ask the right questions in my information requests, but I sent multiple rounds of discovery to MP about these issues. Regardless of what type of cost estimates I asked for, the Company's answer was that it did not have them. I view this as a problem with MP's proposal.

In addition, I also wish to address the engineering opinion that MP provided, which states that it may be possible to operate BEC 3 and 4 until 2050. While I have described this document as an engineering opinion, it is important to recognize that it is

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[37] OAG Information Request No. 1156, Schedule SL-10.
[38] OAG Information Request No. 1157, Schedule SL-11.

only three pages long. It does not include any technical information or cost estimates. In my opinion, this evidence falls short of what is needed to justify a significant life extension for an electric generating facility.

4. Long-Run Increased Returns For Shareholders.

Q. How is depreciation expense related to returns for shareholders?

A. Like all of its capital investments, MP earns a return on the rate base value of BEC 3 and 4. Normally, the rate base booked for an investment is reduced by a set amount—the depreciation expense—each year. In terms of ratemaking, the utility recovers the *operating cost* of the depreciation expense, plus the *return* on the average rate base, which reflects the depreciation expense charged in the Test Year.

To provide a simple example, imagine an investment with a value of $100, an annual depreciation expense of $10, and a rate of return of 10%, during a Test Year. The depreciation expense of $10 will be subtracted from the rate base value of $100, leaving a remaining rate base of $90. The utility would be entitled to a return of $9.50—10% of the average rate base.

If, instead, the depreciation expense was only $5 because the depreciation was being charged over a longer period of time because the depreciation schedule is extended, the utility would earn a return of $9.75—10% of the average rate base of $97.50. In this example, the Company earns an extra $0.25 in the Test Year, and will still recover the full depreciation expense over the life of the investment.

Q. What is your concern with returns for BEC 3 and 4?

A. I am concerned that extending the depreciation schedule for BEC 3 and 4 would increase the amount of returns earned by shareholders as compared to returns shareholders would earn under a shorter depreciation schedule. The Company will likely fully depreciate

BEC 3 and 4 no matter how long the depreciation schedule—it is only a question of timing. Regardless of whether the remaining lives of the units run until 2034 and 2035, or 2050, the Company will likely recover its full depreciation expense over that time period unless the Commission disallows recovery of part or all of the expenses.

But if the depreciation schedule is extended, the rate base balance of the assets will remain higher for longer. This would lead to increased returns for shareholders over the life of the project, compared to the existing depreciation schedule.

Q. Can you provide an example?

A. Yes. Under the Company's extended depreciation schedule, the average rate base balance of BEC 4 is $263,876,140 (MN Jurisdiction) after incorporating depreciation expense of $11,008,345 (MN Jurisdiction), with the Company earning a return of $30,319,368 (MN Jurisdiction).[39]

If, on the other hand, the existing depreciation schedule is used, the depreciation expense would be $20,307,795 (MN Jurisdiction)—higher than the alternative. This would lead to a lower average rate base of $261,150,006 (MN Jurisdiction) on which the Company earns a lower return of $30,006,136 (MN Jurisdiction).[40]

This pattern would be repeated each year under the Company's proposal. It would delay recovery of the depreciation expense, which the Company will get eventually regardless of the depreciation schedule, but increase the return on rate base earned by shareholders.

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[39] OAG Information Request No. 1154, Schedule SL-12.
[40] *Id.*

Q. Were you able to calculate the total amount of increased returns?

A. I asked the Company to do so for me, but its response to OAG Information Request No. 1154 was not the amount of returns for the entire period of the extended depreciation schedule and I do not think the Company provided what I was asking for.

While I did not calculate the cost impact over the entire extended period of the depreciation schedule, the Company did provide calculations to compare the costs for the Test Year. The Company's proposal for BEC 3 and 4 produces depreciation expenses of $18,654,731[41] (MN Jurisdiction) which is $16,488,411[42] less than the depreciation expense of $35,143,142 (MN Jurisdiction) for these units under the existing depreciation schedule, but it also increased the Test Year returns earned on BEC 3 and 4 by $555,377[43] (MN Jurisdiction) (using the Company's proposed rate of return).[44]

To clarify, my calculations demonstrate that MP's depreciation proposal increases the amount of returns earned on BEC 3 and 4 by $555,377 during the Test Year. By delaying recovery of depreciation expenses, shareholders would get more than half a million dollars in additional returns for the Test Year.

Q. What is your conclusion regarding increased returns for shareholders?

A. I view it as concerning. I do not think the problem would be sufficient, alone, to reject MP's depreciation proposal, but it is something that the Commission should be aware of. It may be in the best interests of shareholders to delay recovery of depreciation expense in return for increase capital returns over a longer period of time, but it is not necessarily in the best interests of ratepayers.

[41] $7,646,386 + $11,008,345
[42] $18,654,731 – ($14,835,347 + $20,307,795)
[43] ($20,492,055 + $30,319,368) – ($20,249,910 - $30,006,136)
[44] OAG Information Request No. 1154, Schedule SL-12.

5. Delay Of Coal Retirements.

Q. How are coal retirements related to depreciation expense?

A. As the Commission is aware, there is often significant pressure to explore the possibility of early retirement for coal-fired generating plants. One reason is related to emissions. Environmental advocates often recommend that the Commission and other regulators seek to replace carbon-emitting generation with carbon-free generation such as wind, hydro, or solar. In addition, environmental advocates sometimes recommend that the Commission require utilities to retire fossil fuel power plants, in particular coal-fired plants, before the end of their operational lives in order to reduce the carbon emissions of utilities in the state.

There has also been economic pressure to consider early retirement of coal plants. Other types of generation, including fuel-less generation and the possibility for storage in the future, are contributing to poor economics for coal plants. It is my understanding that the Commission recently directed Xcel Energy to retire several coal-fired generators early because they had become uneconomical to run, regardless of environmental impacts.[45]

While the relationship may not be direct, the Commission should be aware that the extended depreciation schedule for BEC 3 and 4 could have an impact on future conversations about early retirement of these coal units.

Q. Please explain further.

A. One problem when a plant is retired early is whether or not a utility can and should recover its undepreciated plant balance. The remaining plant value that is undepreciated

[45] *See In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS (July 18, 2016).

becomes a stranded cost to the utility, and the Commission must decide whether recovery of this cost would be just and reasonable. It seems likely that the magnitude of the undepreciated plant balance at the time of an early retirement could have an impact on the options available to the Commission.

Q. Can you provide an example?

A. Yes. Imagine two coal plants that are both expected to close in 2035. In the year 2030, Plant A has an undepreciated plant balance of $10, while Plant B has an undepreciated plant balance of $100.

If Plant A were retired 5 years early, the Commission would need to decide what to do with only $10 in remaining plant balance. In contrast, retiring Plant B early would be significantly more troublesome because of its large undepreciated plant balance. The Commission would likely face greater resistance from the utility, whose shareholders would be expecting a return on their investment for several years and would have to deal with stranded costs that may not be recoverable.

Q. How does this example relate to BEC 3 and 4?

A. Based on recent experiences, it seems likely that at some point the Commission will be asked to retire BEC 3 and 4 before the end of their useful lives in 2034 or 2035. At the very least, it is likely that the Commission will consider retirement before 2050. My concern is that extending the depreciation schedules for these units would mean that they would have significant, undepreciated plant balances if the decision to retire these units earlier than 2050 is made. While any decision regarding retirement of generating facilities is complicated and would be made based on multiple factors not known at this time, making such a decision for a facility with a large, undepreciated plant balance

would be even more complicated. In such an event, the Commission would be forced to choose whether to require accelerated depreciation expense for ratepayers, stranded costs for the utility and its shareholders, or to keep facilities open longer than would otherwise be in the public interest. The point that I want to make is that decisions about depreciation schedules in this rate case proceeding will have an impact on decisions about plant retirements made ten or fifteen years down the road in other proceedings.

I want to clarify that I am not recommending retirement at any particular time, but I do want to make sure that the Commission recognizes that extending the depreciation schedule for BEC 3 and 4 could have an impact on future decisions regarding the retirement of these units.

6. Recommendation Regarding BEC 3 And 4.

Q. What is your recommendation regarding BEC 3 and 4?

A. I recommend that the Commission deny MP's request to extend the depreciation schedule of the units. MP's proposal would lead to a mechanism by which it could recover stranded costs limiting the Commission's ability to review these costs on a case by case basis to ensure just and reasonable rates. It would require ratepayers in the 2040s to pay for power plants that are currently expected to be closed many years earlier. The proposal would deviate from normal accounting procedures that exist for good reasons. For example, it could lead to insufficient removal dollars at the time of retirement, and increase returns for shareholders compared to the existing depreciation schedule. On top of that, there are no estimates about the costs of operating the plants past their current useful lives, and the proposal could limit the Commission's options regarding retirement of the facilities in the future.

I recognize that this recommendation would have a significant impact on the revenue requirement in this rate case, based on how the Company presented its initial proposal. According to information provided by the Company,[46] this recommendation would increase depreciation expense in the Test Year by $16,488,412 (MN Jurisdiction),[47] and reduce return on rate base by $555,378 (MN Jurisdiction),[48] for a net impact of $15,933,034 (MN Jurisdiction). But I have reviewed this matter carefully and find that the concerns I have discussed above are significant enough to recommend rejection of MP's proposal. Instead, I recommend that the Commission maintain the existing depreciation schedule for BEC 3 and 4.

Further, I believe that there is a better framework in which to consider MP's proposal to separate and extend the depreciation schedule from the operational life of plants. In some ways, MP's proposal is a form of rate moderation. The Company proposes lower rates today by delaying higher rates to the future through the extension, thereby concealing the full impact of its rate increase proposal in this case. Through this lens, rejecting MP's proposal would be appropriate in order to make a decision based on traditional ratemaking practices and standard accounting principles that allow recovery of costs for assets that are used and useful, rather than a decision that uses non-standard accounting practices to conceal and delay rate increases.

[46] OAG Information Request No. 1154, Schedule SL-12.
[47] $35,143,142 - $18,654,731
[48] $50,811,423 - $50,256,045

B. BEC 1 AND 2.

Q. What is the status of BEC 1 and 2?

A. As I discussed above, BEC 1 and 2 are older, smaller coal-fired generators. According to the most recently approved depreciation filing, the operational life of the units is expected to end in 2024. Other factors, however, have led MP to decide that it will retire the units by the end of 2018.

Q. Can you describe the recent history of BEC 1 and 2?

A. Based on the most recently approved Commission orders, BEC 1 and 2 have a remaining life that will end in 2024. On September 29, 2014, MP entered into a Consent Decree with the Environmental Protection Agency ("EPA") and the Minnesota Pollution Control Agency ("MPCA"). The Consent Decree required MP to take some action to reduce SO_2 (sulfer dioxide) emissions from BEC 1 and 2 no later than December 31, 2018. As I understand it, the options available to MP included retiring the facilities or rerouting the emissions from BEC 1 and 2 through the improved scrubbers installed at BEC 3.

In its most recent IRP, MP informed the Commission that it would prefer to continue to operate BEC 1 and 2 until 2024 by rerouting exhaust through BEC 3, and that doing so would require additional investment of $30 million. The Commission determined that "the Company has not demonstrated at this time that its proposed $30 million investment in SO_2 reduction is a reasonable investment to allow the units to run for three years."[49] Ultimately, the Commission ordered MP to "retire Boswell Energy

[49] *In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS at 7–8 (July 18, 2016).

Units 1 and 2 when sufficient energy and capacity are available, but no later than 2022."[50]

After this order, MP decided that it would retire BEC 1 and 2 by the end of 2018. According to Company witness Mr. Skelton, this decision was the result of the Company's strategy to reduce small coal-fired generation, as well as the EPA Consent Decree and the Commission's decision in the IRP.[51]

Q. What is MP's depreciation proposal for BEC 1 and 2?

A. MP is planning to retire BEC 1 and 2 at the end of 2018 rather than in 2024, but would extend the depreciation schedule to 2050.

Q. Would MP's proposal lead to stranded costs?

A. Yes. The Company is asking to recover the cost of depreciation for BEC 1 and 2 for 32 years after the facilities will be closed. Presumably, ratepayers would also continue to pay a return to shareholders on the undepreciated plant balance for 32 years after the units are closed. In other words, the Company is seeking recovery of stranded costs.

Recent changes to Minnesota law provide that the Commission has the legal authority to allow recovery of stranded costs. But, as I discussed above, Minnesota Statutes section 216B.16, subdivision 6 makes clear that the Commission is not required to do so if it would not result in just and reasonable rates. I do not believe that MP's proposal to extend the depreciation schedule for BEC 1 and 2 would result in just and reasonable rates.

[50] *Id.* at 15, ¶6.
[51] Skelton Direct at 19–20.

Q. Can you explain why MP's proposal for BEC 1 and 2 would not result in just and reasonable rates?

A. There are good reasons why the depreciation schedule for investments is normally tied to the operational life of the facilities. It promotes intergenerational equity for customers, by ensuring that the customers who pay for an investment are receiving benefits from those investments. It also is consistent with normal accounting principles and the Commission's existing rules, as discussed previously.

MP's proposal would deviate from this standard significantly by extending the cost recovery period for the depreciation expenses for more than three decades after the facilities will be closed. I do not believe that this proposal is reasonable, and recommend that the Commission reject MP's proposal to extend recovery of depreciation expense until 32 years after BEC 1 and 2 will be retired.

Q. What options does the Commission have if it does not adopt MP's recommendation for BEC 1 and 2?

A. The Commission has several options. First, the Commission could maintain its decision for the depreciation schedule and operational life ending in 2022, as decided in MP's IRP proceeding.[52]

Second, the Commission could allow recovery of the accelerated depreciation expense associated with BEC 1 and 2 retiring at the end of 2018 so that the facilities are fully depreciated by the time they are retired in 2018. This would increase depreciation expense and reduce returns on rate base in the Test Year, but would have the significant benefit of avoiding completely the issue of stranded costs. Effectively, the Commission

[52] *In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690. ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS at 6–7 (July 18, 2016).

would be concluding that the new operational life of BEC 1 and 2 will end in 2018, and adjusting the depreciation schedule to match it without separating the two as proposed by MP. The rate impact of this option would be larger than the other options, and could have a significant impact on the revenue requirement in this case.

There may be other options to move forward, and I am open to considering them as they arise throughout the case.

Q. What is your recommendation for BEC 1 and 2?

A. I do not have a specific recommendation at this time because I believe it is important that MP address my concerns about double-counting capacity and energy costs, outlined in Section XIII, before reaching a decision on the useful lives for BEC 1 and 2. Regardless of which proposal the Commission approves, I recommend that the Commission also order ratepayer protections to end the recovery of depreciation expenses and rate base earnings for these units once they are fully depreciated. In this circumstance, I believe it would be reasonable to create sunset provisions to end recovery of the costs for BEC 1 and 2 so that ratepayers are not paying for these units after they are fully depreciated.

Once MP responds to my concerns outlined in Section XIII, I may update my recommendation regarding BEC 1 and 2.

C. SUMMARY OF BEC RECOMMENDATIONS.

Q. Can you summarize your recommendations regarding depreciation at BEC?

A. I recommend that the Commission deny MP's proposal to combine the BEC units into one depreciation schedule and extend recovery of depreciation expenses to 2050, for the reasons I have described above. Regarding BEC 1 and 2, I recommend that the Commission reject MP's proposal to extend the cost recovery of depreciation expense to 2050, but do not have a specific recommendation regarding how to handle the useful

lives and depreciation schedule at this time. After the Company addresses my concerns regarding double-counting of capacity and energy costs, below, I may refine my recommendation regarding BEC 1 and 2. Regarding BEC 3 and 4, I recommend that the Commission reject MP's proposal and take no action to separate the current existing remaining lives from the depreciation schedules in this rate case proceeding. If the Company seeks to change the depreciation schedule for BEC 3 and 4, I believe the only reasonable way to do so would be to produce evidence that would justify a modification of the estimated operational life. An appropriate venue to pursue that issue would likely be in the Company's IRP when long-term resource decisions are made.

Regarding the BEC Common Facilities, it is my understanding that the operational life and depreciation schedule is based on an averaging of the remaining BEC investments,[53] and I recommend that it continue to be treated in whatever manner is currently applied.

The total cost impact of this recommendation would be an increase in the revenue requirement of $15,936,118 (MN Jurisdiction) from the Company's proposal.[54] While it would not normally be in the best interest of ratepayers to recommend actions that cause an increase to the revenue requirement, in light of the significant concerns with MP's proposal I believe that it is the most reasonable thing for the Commission to do in this case.

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[53] *In the Matter of Minnesota Power's 2016 Remaining Life Depreciation Petition*, Docket No. E-015/D-16-797, ORDER, at 7 (Apr. 21, 2017).

[54] ($97,972,954 + $128,013,352) - ($91,025,090 + $119,025,098)

VI. COSTS RELATED TO EARLY RETIREMENT OF BEC 1 AND 2

Q. What is your concern related to the cost of early retirement of BEC 1 and 2?

A. As I discussed above, in MP's most recent IRP the Commission ordered the Company to retire BEC 1 and 2 "when sufficient energy and capacity are available, but no later than 2022."[55] The Commission noted that "The Department believed that replacement generation could be in place by 2022."[56] The Company indicates that it has decided to retire BEC 1 and 2 by the end of 2018, but I am not aware of any place in the record of this proceeding which the Company discusses how it has obtained "sufficient energy and capacity" to replace electricity that would otherwise be generated by BEC 1 and 2.

My concern is that the Commission conditioned its order regarding BEC 1 and 2—MP was ordered to retire the facilities no later than 2022, but only after it had obtained replacement energy and capacity. Based on my review of the record, I do not see any discussion of how the Company has obtained replacement energy and capacity, or the cost of doing so.

Essentially, my concern is that there could be a type of double recovery. BEC 1 and 2 produce approximately 134 MW in capacity, and the associated energy. Ratepayers will continue to pay for the capacity and energy costs related to BEC 1 and 2 until a future rate case adjusts rates again. Because MP has decided to retire the facilities in 2018, I assume that the Company must have complied with the Commission's requirement that it obtain replacement capacity and energy before the retirements take place. My concern is that MP may have included the cost of *both* BEC 1 and 2 *and* the

[55] *In the Matter of Minnesota Power's 2016–2030 Integrated Resource Plan*, Docket No. E-015/RP-15-690. ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS at 7–8 (July 18, 2016).
[56] *Id.*

replacement for BEC 1 and 2 in the Test Year. It is unclear whether the Company should recover both types of costs at the same time.

Because I did not locate any testimony where the Company discussed the required replacement for BEC 1 and 2, I was not able to confirm whether the Company had a plan for replacement capacity and energy, whether its plan was reasonable, or whether its cost recovery proposal was reasonable. For that reason, I request that MP provide testimony regarding the requirement that it obtain replacement capacity and energy before retiring BEC 1 and 2, the costs of doing so, and how those costs are reflected in this rate case.

VII. STORM DAMAGE AMORTIZATION EXPENSE

Q. Is the Company requesting cost recovery for storm damage costs associated with storms on July 21, 2016?

A. Yes. The Company has included $732,272 in the 2017 Test Year to reflect the four-year amortization of $2,929,088 in storm damage costs that were incurred as a result of the storms on July 21, 2016.

Q. Did the Company seek approval to defer and amortize these storm damage costs?

A. Yes. The Company filed its request to defer these operating and maintenance costs totaling $2,929,088 on August 1, 2016 in a separate deferred accounting docket.[57]

Q. What did the Commission order in that docket?

A. The Commission denied the Company's request to defer and amortize the storm damage costs and found that the Company did not demonstrate that these were "unusual and

[57] *In the Matter of a Petition for Approval of Deferred Accounting Treatment of Costs Related to the 2016 Storm Response and Recovery*, Docket No. E-015/M-16-648 (Aug. 1, 2016).

unforeseen, and would have significant impact on its financial condition."[58] Furthermore, the Commission found that "while the impact of the 2016 storm was more significant than past storms, there are years where Minnesota Power experiences no storms or very small storms, and the Company therefore incurs less costs than those built into rates." [59]

Q. Why did the Company include amortization expense in the Test Year if the Commission denied the Company's request?

A. The Company included this amortization expense in the 2017 Test Year for general rates because the Commission had not yet decided the 2016 deferred accounting docket at the time the Company filed this rate increase request.

Q. What is your recommendation?

A. I recommend that the amortization expense of $732,272 should be excluded from the 2017 Test Year, consistent with the Commission's decision to deny the Company's request to amortize this expense.

VIII. SAPPI/CLOQUET GENERATOR AMORTIZATION EXPENSE

Q. Provide a summary of this amortization expense and a summary of the history of events.

A. The Sappi/Cloquet generator is installed at a paper mill that is owned by a company called Sappi. The generator was previously owned by the Company, but was purchased by Sappi from the Company on July 1, 2016 for one dollar. The Company has included

[58] *In the Matter of a Petition for Approval of Deferred Accounting Treatment of Costs Related to the 2016 Storm Response and Recovery*, ORDER DENYING PETITION FOR DEFERRED ACCOUNTING TREATMENT, Docket No. E-015/M-16-648 (Jan. 10, 2017).
[59] *Id.*

$275,745 in amortization expense associated with the increase in depreciation expense for the Sappi/Cloquet generator. This increase in depreciation expense resulted from the Commission's order on September 19, 2016 that the Company shorten the useful life of the Sappi/Cloquet generator from ten years ending in 2024, to two years ending in 2016 because the Company had already sold the Sappi/Cloquet generator and should not be depreciating an asset it no longer owned.[60] The depreciation expense that would have been charged over a ten year period would have to be accelerated and charged over two years, which would lead to an increase in the amount of depreciation expense to be charged each year. Since this increase in depreciation expense was not included in base rates at that time, the Company filed a separate request for deferred accounting on October 28, 2016 to request deferral of the increase in depreciation costs totaling $2,205,958.[61] The Department recommended that the Commission deny the Company's deferred accounting request. Before the Commission was able to make its decision, however, the Company withdrew its deferred accounting request on December 20, 2016.

Q. Why did the Company withdraw its deferred accounting request?

A. The Company explained that its decision to withdraw the request was based on the Commission's decision to deny the Company's separate request for deferred accounting treatment for storm damage costs, as well as the Company's determination, through further analysis, that no depreciation expense issues for Sappi/Cloquet needed to be addressed.

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[60] *In the Matter of Minnesota Power's 2015 Remaining Life Depreciation Petition*, Docket No. E-015/D-15-711, ORDER APPROVING REMAINING LIVES AND SALVAGE RATES AS MODIFIED, AND FILING REQUIREMENTS (Sept. 19, 2016).

[61] *In the Matter of a Petition for Approval of Deferred Accounting Treatment of Costs Related to Depreciation Expenses for Sappi-Generator No. 5*, Docket No. E-015/M-16-876 (Oct. 28, 2016).

Q. **What is your recommendation?**

A. I recommend that the Company remove $275,745 of amortization expense associated with the Sappi/Cloquet generator out of the 2017 Test Year. This is consistent with the Commission's decision to shorten the useful life of the generator to the end of 2016, and to reflect the fact that the asset is no longer owned by the Company.

IX. CREDIT CARD PROCESSING FEES

Q. **Explain what these credit card processing fees are.**

A. The Company has included $350,000 in the 2017 Test Year to cover the costs that customers currently have to pay a third-party credit card processor, for the convenience of making electronic payments with a credit or debit card.

Q. **What is the Company's justification for asking ratepayers to cover this convenience cost?**

A. The Company points to several sources, such as J.D. Powers, the National Association of State Utility Consumer Advocates ("NASUCA"), and the Public Utilities Fortnightly, that have published articles stating that eliminating payment fees for customers would lead to "enhanced customer convenience, satisfaction, and improved quality of service," convenience fees eroding the purchasing power of debit cards and making it hard for customers to pay for utility service, and that prepaid credit and debit cards are increasing in popularity among younger customers and low-income customers.[62] The NASUCA document that the Company cited to is a Resolution titled "Urging Utilities to Eliminate 'Convenience' Fees for Paying Utility Bills with Debit and Credit Cards and Urging

[62] Koecher Direct at 29.

Appropriate State Regulatory Oversight" ("Resolution").[63] The OAG is a member of NASUCA, so I reviewed this resolution to determine whether the Company's proposal is consistent with the concerns raised in the Resolution.

Q. Does the Company's proposal address the concerns in the NASUCA resolution?

A. No. The Resolution pointed out that one of the reasons for the high fees attached to utility payments by credit or debit cards is that many utilities process these charges through third-party vendors that assess large fees.[64] The Resolution suggests that if utilities would accept payments directly instead, the costs would be "likely comparable to the cost of processing payments by other means, including traditional checks."[65] Ultimately, the Resolution recommends that utilities drop third-party vendors and instead accept debit and credit payments directly in order to reduce costs and protect low-income customers. The Company's proposal would do nothing to address this primary concern in the Resolution because ratepayers would *still* be assessed third-party vendor processing fees.

Q. Does the NASUCA Resolution address any other concerns?

A. Yes. The Resolution also points out that there should be cost savings from eliminating credit card fees. The Resolution suggests that cost savings could come from "more immediate receipt of payment, lower collection risks and uncollectible debt expense, improved cash flow and reduced working cost of capital."[66] I agree that increasing payments from credit and debit cards, and particularly making it easier for low-income

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[63] *Id.* at 30.

[64] RESOLUTION 2012-07 URGING UTILITIES TO ELIMINATE 'CONVENIENCE' FEES FOR PAYING UTILITY BILLS WITH DEBIT AND CREDIT CARDS AND URGING APPROPRIATE STATE REGULATORY OVERSIGHT, NASUCA (Nov. 13, 2012), *available at* https://nasuca.org/2012-07-urging-utilities-to-eliminate-convenience-fees-for-paying-utility-bills-with-debit-and-credit-cards-and-urging-appropriate-state-regulatory-oversight/.

[65] *Id.* at 2.

[66] *Id.*

customers to make such payments, could create cost savings in these categories. MP has made no attempt to calculate the cost savings from increased credit or debit payments, and they are not reflected in this case at all.

Q. What is your conclusion regarding the NASUCA Resolution?

A. I conclude that the Company has not addressed the concerns of the NASUCA Resolution. Specifically the suggestion that debit and credit card payment processing would cost less overall if utilities would accept payments directly rather than through third party vendors, and that there should be cost savings from increasing such payments.

Q. What is your recommendation?

A. Based on the specific facts of this case, at this time I recommend that MP's proposal be rejected, including its request to increase the revenue requirement by $350,000, because the Company's proposal does not address the concerns of the NASUCA Resolution. Instead, I recommend that the Commission order the Company to investigate the concerns in the NASUCA resolution regarding third-party vendor processing charges and the cost savings associated with increased debit and credit card payments, and adjust its proposal to accept debit and credit card payments directly if it is less expensive to do so. I also recommend that the Commission order the Company to conduct a review of the potential cost savings as discussed in the Resolution.

X. CHARITABLE CONTRIBUTIONS

Q. Is the Company requesting recovery of charitable contributions?

A. Yes. As shown in MP Exhibit_(MAP) Direct Schedule G-2, the Company included $453,128 in the 2017 Test Year for charitable contributions. This amount represents 50

percent of Company's three-year average spending for charitable contribution from 2013 to 2015.

Q. Why is only 50 percent included in the 2017 Test Year?

A. Including only 50 percent in the Test Year is consistent with Minnesota Statutes section 216B.16, subdivision 9, and the Commission's Statement of Policy on Charitable Contributions issued on June 14, 1982.[67]

Q. How did the Company calculate the 2017 Test Year amount of charitable contributions to be recovered from ratepayers?

A. The Company first calculated a three-year average of its actual charitable contributions from 2013, 2014, and 2015. The Company then adjusted its 2017 budget for charitable spending of $512,000 downward by $58,872 so that its 2017 Test Year budget reflects the three-year average of $453,128.

Q. Did the Company provide how much was spent on charitable contributions in other years?

A. Yes. The Company spent $776,855 in 2012 and $292,080 in 2016.[68]

Q. Are you concerned with the Company's calculation of charitable contributions for its 2017 Test Year?

A. Yes. While the Company uses a three-year average, it appears that the Company's actual charitable contributions have fluctuated significantly between 2012 and 2016. To provide context, I included the charitable contributions from 2012 to 2016, and the 2017 budget, in Table 1. This table shows that charitable contributions have changed significantly from year to year. For example, charitable spending increased by nearly

[67] Minnesota Power Workpapers, Volume 5, ADJ-IS-13c.
[68] *See* OAG Information Request 106, Schedule SL-13.

100% from 2013 to 2014, and then dropped by 74% from 2015 to 2016. And the amount included in the Test Year is 75% greater than the amount spent in the most recent fiscal year.[69] The Commission has considered variance of this level in other rate cases. In the Company's last rate case, the Commission reviewed significant fluctuation in actual spending in 2007, 2008, and 2009.

Table 1			
Charitable Contributions			
Year		**Amount**	**% Variance**
2012 Actual	$	776,855	
2013 Actual	$	533,254	-31%
2014 Actual	$	1,058,473	98%
2015 Actual	$	1,127,042	6%
2016 Actual	$	292,080	-74%
2017 Budget	$	512,000	75%

Q. What information about the Company's last rate case is pertinent for the current rate case?

A. The year-to-year variance in charitable contributions was also an issue in the Company's last rate case, and is shown in Table 2.

Table 2			
Charitable Contributions			
Year		**Amount**	**% Variance**
2007 Actual	$	929,522	
2008 Actual	$	1,068,702	15%
2009 Actual	$	665,707	-38%
2010 Budget	$	1,295,000	95%

In that rate case, the Company wanted to assume its 2010 budget for its 2010 Test Year. The Commission denied the request, and instead determined that "a three-year average is

[69] Podratz Direct at 23.

likely to have more predictive value than data from a single year."[70] Further, the Commission was concerned that the Company had recovered more from ratepayers for charitable contributions than was actually spent and stated that "relying more heavily on factual data than stated intentions is clearly a reasonable strategy for preventing recurrence of over-recovery."[71]

Q. What three years did the Commission order the Company to use in its last rate case?

A. The Commission ordered the Company to use its most recent three years of actual spending to calculate a three-year average to be used to set Test Year charitable contribution expense. In other words, the Company used actual spending from 2007, 2008, and 2009 to calculate the three-year average for its 2010 Test Year.

Q. What three years does the Company use for the calculation in its current rate case?

A. The Company uses actual spending from 2013, 2014, and 2015.

Q. Does the Company explain why it does not use the most recent three years of actual spending?

A. No.

Q. Should the Company use its most recent three years of actual spending?

A. Yes, the Company should use actual spending in 2014, 2015, and 2016 to set its Test Year charitable contribution expense. In addition to this method being consistent with the methodology used in the Company's last rate case, this method also considers the fact that the Company has volatile levels in charitable spending from year to year which could

[70] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 38 (Nov. 2, 2010).
[71] *Id.*

result in actual future spending to be less than what the Company currently plans. Additionally, as pointed out by the Company, charitable contributions are discretionary spending for corporations and can be reduced when a Company experiences unfavorable economic conditions.[72] Since the Company has stated it expects "lower operating income due to northern Minnesota's challenging economic outlook," it is reasonable to use the most recent lower levels of actual spending to set its Test Year charitable contribution expense. I also note that while including 2016 in the average would reduce Test Year expenses somewhat, including 2014 and 2015 would capture two years of very high spending.

Q. What is your recommendation?

A. I recommend that the three-year average is calculated using actual spending from 2014 to 2016 as shown below. This would result in an adjustment to the 2017 Test Year of $99,068 to reduce the Company's 2017 budget of $512,000 to $412,933.

Table 3	
3 Year Average	
Year	**Amount**
2014 Actual	$ 1,058,473
2015 Actual	$ 1,127,042
2016 Actual	$ 292,080
3-year Average	$ 825,865
50% Allowable in Rates	$ 412,933

[72] *Id.*

XI. MEMBERSHIP DUES

Q. Are there membership dues in the 2017 Test Year?

A. Yes. The Company has included its cost for corporate membership dues and individual professional membership dues in its Test Year.

Q. How much is the amount in the 2017 Test Year for each type of membership dues?

A. It is not clear what amount is included in the Test Year for corporate membership dues and individual professional membership dues, because the Company has provided several types of information that are inconsistent.

While the Company has provided a one-page summary of its employee expenses in the Test Year[73] which shows an amount of $1,418,853[74] under the "Dues and Expenses for Memberships in Organizations or Clubs" category, the Company also shows in a separate schedule that $789,962 is included in the Test Year for membership dues.[75] Additionally, the Company states that it has made a Test Year adjustment of $29,039 to organizational dues,[76] but the adjustment amount shown for the "Dues and Expenses for Memberships in Organizational Dues" category in the one-page summary is only $17,514. [77] On top of that, it appears that $149,195 of the total adjustments of $237,194 in the "Lobbying" category of the one-page summary of employee expenses in the Test Year are related to various membership dues that are associated with lobbying activities.[78]

[73] MP Exhibit_(SWM) Direct Schedule 1 2017 Employee Expense Summary.
[74] $1,418,853 - $17,514
[75] MP Exhibit_(MAP) Direct Schedule G-3.
[76] MP Exhibit_(MAP) Supplemental Direct Schedule A-6.
[77] MP Exhibit_(SWM) Direct Schedule 1 2017 Employee Expense Summary.
[78] MP Exhibit_(MAP) Direct Schedule G-3.

It appears that the Company has included subsets of membership dues and adjustments to membership dues in various expense categories, but it is not clear what amount of the total expenses in the "Dues and Expenses for Memberships in Organizational Dues" category pertain to corporate and individual membership dues. These discrepancies suggests that the amount of $1,418,853 shown in the category "Dues and Expenses for Memberships in Organizations or Clubs" may not capture all 2017 Test Year costs of this type of expense.

Q. Did the Company provide a listing of its membership dues?

A. Yes. The Company provided a list of its 2015 corporate and individual membership dues in MP Exhibit_(MAP) Direct Schedule G-3. The Company spent $621,791 on corporate memberships in 2015. The Company spent $65,306 on individual memberships in 2015. The Company spent $14,362 for other business dues.

Q. Besides the lack of clarity on the total amount of membership dues in the 2017 Test Year, do you have any concerns about any specific membership dues?

A. Yes. There are additional membership dues associated with lobbying activities that have not been removed by the Company that should be excluded from the Test Year.

Q. What are the additional membership dues that should be disallowed that have not already been removed by the Company from the Test Year?

A. There are membership dues where the entire annual cost should be removed due to the organization's lobbying activities and legislative efforts, and the inability of the Company to provide information on how much of the membership dues are attributable to the organization's lobbying activities and to other activities that lead to favorable regulatory

and policy outcomes that benefit the utility.[79] The membership dues for the following organizations should be disallowed.

- Edison Electric Institute, including USWAG and UARG
- Western Coal Traffic League
- Utility Water Act Group
- Mining Minnesota
- Minnesota Forest Industries
- Minnesota Timber Producer Association
- National Association of Manufacturers
- American Wood Protection Association
- National Coal Transportation Association
- World Steel Dynamics Incorporated
- National Hydropower Association

Q. Which membership dues related to lobbying activities has the Company already removed from the 2017 Test Year?

A. The Company has currently excluded the entire membership due for the Lignite Coal Council, the entire membership due for the Center for Clean Air Policy, and a portion of the membership due for the Edison Electric Institute ("EEI") that is associated with lobbying activity.[80]

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[79] *See* OAG Information Request 152, Schedule SL-14.
[80] *Id.*

Q. How much of the total cost of each of these memberships have been attributed to lobbying activities and excluded from the Test Year?

A. This is unclear. While the Company stated in MP Exhibit_(MAP) Direct Schedule 3 that it removed $149,195 associated with the lobbying portion of the membership dues for these three organizations, the Company responded with a different amount in OAG Information Request 141 of $153,262. I request that the Company provide the amount of membership dues in the Test Year for EEI, Lignite Coal Council, and Center for Clean Air Policy, in addition to the amount for each membership that was excluded from the Test Year to reflect the lobbying activities of the associations that should not be recovered from ratepayers including amounts that were moved "below-the-line" and the amounts that had to be adjusted out of the 2017 budget.

Q. How does the Company determine the portion of the annual membership dues associated with lobbying activities?

A. The Company explained that "the lobbying portion of . . . [d]ues is calculated and reported each year using the Internal Revenue Code's (IRC) definition of "lobbying and political activities" as required to be reported on IRS Form 990."[81]

Q. What are the Internal Revenue Service ("IRS") definitions for lobbying and political expenses?

A. The IRS broadly defines lobbying and political expenditures in IRC section 162(e), which includes those expenses in connection with "1. Influencing legislation, 2. Participating or intervening in any political campaign on behalf of (or in opposition to) any candidate for public office, 3. Attempting to influence the general public with respect

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[81] *See* OAG Information Request 117, Schedule SL-15.

to elections, legislative matters, or referendums, and 4. Any direct communication with a covered executive branch official in an attempt to influence the person's official actions or positions."[82]

Q. Do the organizations provide the Company with a notice on the portion of dues that is attributable to nondeductible lobbying expenses?

A. In most instances, the organization provides the percentage of membership dues related to the activities that have been defined under IRC section 162(e). While this IRS definition of lobbying expenses is used for tax purposes and for determining nondeductible business expenses, it is not inclusive of all activities that lead to favorable regulatory and policy outcomes that benefit the utility.

Q. Have there been any public utilities commissions that have found a larger portion of an organization's activities were attributed to lobbying and other political activities than were reported by the organization?

A. Yes. There are at least two general rate cases in the state of California where the California Public Utilities Commission ("CPUC") found that a greater portion of the organization's activities was attributable to lobbying and political activities than was reported by the organization.

Q. Provide a brief summary of those general rate cases.

A. The first is Pacific Gas & Electric's ("PG&E") general rate case in 2014.[83] PG&E had proposed to exclude only 25 percent of its EEI annual membership dues associated with

[82] INTERNAL REVENUE SERVICE, NONDEDUCTIBLE LOBBYING AND POLITICAL EXPENDITURES, https://www.irs.gov/charities-non-profits/other-non-profits/nondeductible-lobbying-and-political-expenditures (last visited May 24, 2017).

lobbying activities from recovery. However, information provided by an intervening party[84] showed EEI lobbying and political activities in 2005 as audited by the National Association of Regulatory Utility Commissioners ("NARUC"), and EEI lobbying activities in 2009 as provided to the Arkansas Public Service Commission in a general rate case in that state had exceeded the 25 percent that PG&E was proposing to exclude. The CPUC found that EEI activity pertained to "lobbying, legislative policy research and advocacy, regulatory advocacy, public relations, advertising, donations, and club dues" were categories of expenses that offered no ratepayer benefits; therefore, the CPUC disallowed 43 percent of the EEI annual membership dues.

The second is Southern California Edison's ("SCE") general rate case in 2015.[85] SCE had proposed to exclude only 24 percent of its EEI annual membership dues from recovery. However, the CPUC found that SCE did not fully follow the methodology to exclude all cost categories it had earlier disallowed in the PG&E 2014 general rate case that offered no ratepayer benefits, and disallowed 48 percent of the EEI annual membership dues.

(Footnote Continued from Previous Page)

[83] *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2014 (U39M)*, Application No. 12-11-009, DECISION 14-08-032, 2014 WL 4248558 (Cal. P.U.C. Aug. 14, 2014).

[84] *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2014 (U39M)*, Application No. 12-11-009, DECISION 14-08-032, 2014 WL 4248558 (Cal. P.U.C. Aug. 14, 2014).

[85] *Application of Southern California Edison Company (U338E) for Authority to, among other things, Increase its Authorized Revenues for Electric Service in 2015, and to reflect that increase in Rates*, Application No. 13-11-003, DECISION 15-11-021, 2015 WL 7351928 (Cal. P.U.C. Nov. 12, 2015).

Q. Explain what the NARUC audit was and the operating expense categories used in the audit.

A. According to the Resource Library on the NARUC website, the Committee on Utility Association Oversight was formed on July 30, 1986 in response to concerns about utilities recovering association dues.[86] There are nine operating expense categories used in the NARUC audit to capture an organization's activities.[87] They are:

- Legislative Advocacy
- Legislative Policy Research
- Regulatory Advocacy
- Regulatory Policy Research
- Advertising
- Marketing
- Utility Operations and Engineering
- Finance, Legal, Planning, and Customer Service
- Public Relations

Q. What do the different operating expense categories suggest regarding the different types of political activities there are?

A. The expense categories used by NARUC to categorize the activities an organization is involved with suggests that there are many types of activities to influence the legislative and regulatory process than just obvious direct lobbying activity. While the IRS has its

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[86] RESOLUTION REGARDING DISCONTINUATION OF THE COMMITTEE ON UTILITY OVERSIGHT, NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (Mar. 8, 2000), http://pubs naruc.org/pub/5398B543-2354-D714-51D3-90ACAB1DA952.

[87] *Application of Southern California Edison Company (U338E) for Authority to, among other things, Increase its Authorized Revenues for Electric Service in 2015, and to reflect that increase in Rates*, Application No. 13-11-003, DECISION 15-11-021, 2015 WL 7351928 (Cal. P.U.C. Nov. 12, 2015).

definition for determining lobbying activities for tax purposes, there are activities that organizations can engage in that impact regulatory and policy outcomes that benefit the utility, which the CPUC has determined do not benefit ratepayers.

Q. What is the total amount associated with the corporate membership dues that should be disallowed in the Test Year?

A. This is unclear. I request that the Company provide the amount of membership dues in the Test Year for the organizations below, in addition to the amount for each membership that was excluded from the Test Year to reflect the lobbying activities of the associations that should not be recovered from ratepayers including amounts that were moved "below-the-line" and the amounts that had to be adjusted out of the 2017 budget.

- Edison Electric Institute, including USWAG and UARG
- Western Coal Traffic League
- Utility Water Act Group
- Mining Minnesota
- Minnesota Forest Industries
- Minnesota Timber Producer Association
- National Association of Manufacturers
- American Wood Protection Association
- National Coal Transportation Association
- World Steel Dynamics Incorporated
- National Hydropower Association

Q. Explain why the entire amount of EEI membership dues should be disallowed from recovery?

A. There are two primary reasons why ratepayers should not have to pay for the EEI member dues. First, the EEI is a national organization engaged in extensive lobbying activities on behalf of its investor owned electric utility members. Its website indicates that it "advocates on behalf of our investor-owned electric company members before Congress, federal and state regulatory agencies, the courts, and various industry organizations."[88] Additionally, roughly 35 percent or $124,500 of Minnesota Power's annual EEI membership dues are to pay for activities furthered by the Utility Solid Waste Activity Group ("USWAG") and the Utility Air Regulatory Group ("UARG").[89] USWAG engages in regulatory advocacy for its utility, energy, and industry association members, including EEI and the American Gas Association (AGA).[90] UARG does not have a website, but it has engaged in legal proceedings with the U.S. Environmental Protection Agency ("EPA") on the Clean Air Act[91] and the Clean Power Plan.[92]

The second reason for disallowing recovery of EEI membership dues is that the Company has not been able to provide a breakdown of the annual membership dues based on the activities that EEI is engaged in that would benefit ratepayers. Further, EEI's funding of USWAG and UARG make it extremely difficult to determine the

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88 EDISON ELECTRIC INSTITUTE, ISSUES AND POLICY, http://www.eei.org/issuesandpolicy/Pages/default.aspx (last visited May 24, 2017).

89 *See* OAG Information Request 117, Schedule SL-15.

90 UTILITY SOLID WASTE ACTIVITIES GROUP, ABOUT USWAG, http://www.uswag.org/About/Pages/default.aspx (last visited May 24, 2017).

91 *Utility Air Regulatory Group v. Environmental Protection Agency*, 134 S.Ct. 2427 (2014).

92 Paul Ciampoli, *APPA and UARG seek review of final Clean Power Plan*, AMERICAN PUBLIC POWER ASSOCIATION (Oct. 26, 2015), http://www.publicpower.org/Media/daily/ArticleDetail.cfm?ItemNumber=44701.

activities of these third-party organizations that benefit Minnesota ratepayers, for which ratepayers should pay for.

Q. Explain why the entire amount of Western Coal Traffic League ("WCTL") membership dues should be disallowed from recovery?

A. There are two primary reasons. First, this organization is located in Washington, DC in close proximity to legislative activities and regulatory agencies, and it engages in advocacy work for its investor-owned company members, cooperative, and governmental members though legal proceedings.[93] Second, while the WCTL website states it is involved in "significant matter impacting the delivered prices of western coal," Minnesota Power has not been able to separate WCTL activities that are related to lobbying and those activities that do not influence legislative and regulatory policy that benefit Minnesota ratepayers.[94] Minnesota Power should treat the membership dues for this organization the same as they treated its membership dues for the Lignite Coal Council, which is to remove it from the 2017 Test Year.

Q. Explain why the entire amount of the Utility Water Act Group ("UWAG") membership dues should be disallowed from recovery?

A. There are two primary reasons. First, the organization is a lobbying group that represents EEI and other national trade organizations and energy companies with a stated purpose "to participate on behalf of its members in EPA's rulemakings under the CWA and in

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[93] *Our History*, WESTERN COAL TRAFFIC LEAGUE, http://www.westerncoaltrafficleague.com /index.php?option=com_content&view=article&id=2&Itemid=2 (last visited May 24, 2017).
[94] *See* OAG Information Request 152, Schedule SL-14.

litigation arising from those rulemakings."[95] Second, it is not clear what benefits Minnesota Power ratepayers obtain from the activities of this organization.

Q. Explain why the entire membership dues for Minnesota Mining, Minnesota Forest Industries, Minnesota Timber Producer Association, National Association of Manufacturers, American Wood Protection Association, National Coal Transportation Association, and World Steel Dynamics Incorporated should be disallowed from recovery?

A. There are two primary reasons. First, these industry trade associations are not directly involved in the electric utility industry, and it is unclear how membership in these industry trade associations will benefit Minnesota Power ratepayers and are necessary for the provision of utility service. Second, Minnesota Power has not provided a breakout of the activities for each of these organizations that benefit Minnesota Power ratepayers and are not related to lobbying and those activities that do not influence legislative and regulatory policy.[96]

Q. Explain why the entire amount of the National Hydropower Association ("NHA") membership dues should be disallowed from recovery?

A. There are three primary reasons. First, NHA's website suggests it has an influential lobbying role in that it states it is "a powerful advocacy voice among U.S. decision makers, the general public and the international community" and that "through membership, individuals and organizations gain access to regulatory bodies, influence

[95] Comments of the Utility Water Act Group on Revised Draft Permit for the Merrimack Station NPDES Permit No. NH0001465 (Aug. 18, 2014), *available at* www3.epa.gov/region1/npdes/merrimackstation/pdfs/Comments2RevisedDraftPermit/UWAGComments.pdf.

[96] *See* OAG Information Request 152, Schedule SL-14.

over energy and environmental policy. . ."[97] NHA's 2015 Annual Report also lists a 12-month legislative and regulatory timeline in which it was involved in many activities that impacted regulatory and policy outcomes.[98] Second, while it appears that NHA has an "Operational Excellence Program" that is a voluntary event reporting system that tracks operational information, as well as best practices and lessons learned to be shared among utility companies, it is unclear whether Minnesota Power participates in this program. Furthermore, Minnesota Power has not provided a breakout of NHA activities that are related to lobbying and those activities that do not influence legislative and regulatory policy that benefit Minnesota ratepayers.[99]

Q. Are there any membership dues that the Commission have disallowed because of the potential lobbying activities of the organization?

A. Yes. The Commission found in the 2015 CenterPoint Energy general rate case that the utility's request to recover its $177,584 annual membership dues in the American Gas Association would lead to unjust and unreasonable rates for ratepayers. The reason for denying the utility's request was because it was "impossible to determine on this record the portion of AGA dues that are used for lobbying, or to perform a reasoned analysis about whether or to what extent the lobbying served ratepayer interests."[100] The Commission stated that "[t]he Commission does not wish to tacitly reward the commingling of unrecoverable lobbying expenses with expenses that may otherwise be

[97] *Who We Are*, NATIONAL HYDROPOWER ASSOCIATION, http://www hydro.org/about-nha/who-we-are/ (last visited May 24, 2017).

[98] NATIONAL HYDROPOWER ASSOCIATION, 2015 ANNUAL REPORT, *available at* http://anf5l2g5jkf16p6te3ljwwpk.wpengine.netdna-cdn.com/wp-content/uploads/2016/08/NHA-2015-Annual-Report.pdf.

[99] *See* OAG Information Request 152, Schedule SL-14.

[100] *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 27 (June 3, 2016).

justified for recovery. The burden of justifying this expense rests on the Company, and doubt must be resolved in the ratepayers' favor."

Q. Besides the corporate membership dues above, are there individual membership dues that should be disallowed from the 2017 Test Year?

A. Yes. The Company has included the cost of membership to the Nebraska State Bar Association[101] and for a Wisconsin CPA renewal.[102] A $224 adjustment should be made to decrease the Test Year membership dues for these two items.

Q. Why should this membership be disallowed?

A. These membership are for the benefit of the employees to practice in other states outside of the Company's service territory. Minnesota ratepayers should not have to pay for this membership as it is not necessary for the provision of utility service.

Q. What is your recommendation?

A. I request that the Company provide the total amount of organizational dues included in the 2017 Test Year, itemizing each membership under corporate dues and individual memberships. Additionally, for future rate cases, I recommend the Commission order the Company to report all association activity using the NARUC audit categories for the cost of membership dues that the Company is requesting recovery for. Providing this detailed level of information on the type of work an association is performing on behalf of the utility would allow for a better analysis of whether that work is related to lobbying activities or other activities that benefit ratepayers. Since this information is not provided for the annual membership dues to the organizations I discussed above, I recommend the disallowance of those entire annual membership dues. Additionally, the dues totaling

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[101] *See* OAG Information Request 107, Schedule SL-16.
[102] MP Exhibit_(MAP) Direct Schedule G-3.

$224 associated with practicing in other states should be removed from the Test Year. The amount of membership dues to be disallowed will be determined once the Company clarifies the amount of membership dues in the Test Year.

XII. EMPLOYEE GIFTS

Q. Does the Company include employee gifts in the 2017 Test Year?

A. Yes. The Company has requested recovery of employee gifts as shown in MP Exhibit_(NRJ) Direct Schedule 3 of $25,823 for service awards, $20,110 for retirement awards, and $2,887 for memorials for a total of $48,820.

Q. Are there any discrepancies between MP Exhibit_(NRJ) Direct Schedule 3 and other information provided by the Company for employee gifts?

A. Yes, there are discrepancies for various employee gift categories that the Company should clarify and provide a reconciliation to explain the differences. Specifically, the actual costs incurred for each gift category and shown for MP Exhibit_(NRJ) Direct Schedule 3 is different from the actual costs shown in the Company's request to an OAG Information Request,[103] and the Company's response to a Commission Information Request.[104] It is unclear if the actual gift costs presented on MP Exhibit_(NRJ) Direct Schedule 3 reflect all costs since the actual gift costs provided in response to OAG Information Request are greater for each year from 2012 to 2016. The Company should explain why the gift categories provided in the OAG and Commission Information Requests do not appear to be included in MP Exhibit_(NRJ) Direct Schedule 3 and

[103] *See* OAG Information Request 118, Schedule SL-18.
[104] *See* MPUC Information Request 3, Schedule SL-19.

provide the correct actual cost amount. Additionally, the Company needs to provide the 2017 Test Year amount for all categories that it has used in its different responses.

Q. What are the gift categories and amounts shown in the Company's responses to the Information Requests?

A. Below is a table summarizing the actual costs for each gift category from 2012 to 2016 that was provided in the OAG Information Request 118.

TABLE 4
Actual Employee Gift Costs, per OAG IR 118

	2012	2013	2014	2015	2016
Retirement/Service Award Gift Cards		$ 39,771	$ 79,630	$ 84,479	$ 43,805
Spot Bonus - Gift Card	$ 53,000	$ 127,786	$ 78,115	$ 45,210	$ 78,217
Total	**$ 53,000**	**$ 167,557**	**$ 157,745**	**$ 129,689**	**$ 122,022**

Below is a table summarizing the actual costs for each gift category for the 2017 Test Year that was provided in the Commission Information Request 3.

TABLE 5
Employee Gift Costs, per MPUC IR 3

	2017 Test Year
Service Awards	$ 8,710
Retirement Awards	$ 6,880
Safety Awards	$ 4,318
Total	**$ 19,908**

The categories and actual costs from these two Information Requests are not comparable to the actual cost information and categories shown in MP Exhibit_(NRJ) Direct Schedule 3 summarized in Table 6 below.

TABLE 6
Employee Gift Costs, per Direct Schedule 3

	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Proj	2017 Test Year
Service Awards		$ 38,141	$ 39,584	$ 44,755	$ 33,691	$ 25,823
Retirement Awards		$ 11,194	$ 20,478	$ 22,781	$ 20,378	$ 20,110
Memorials		$ 2,964	$ 2,214	$ 2,008	$ 2,925	$ 2,887
Total	**N/A**	**$ 52,299**	**$ 62,276**	**$ 69,544**	**$ 56,994**	**$ 48,820**

Q. What was the Commission's order regarding employee gifts from the Company's last rate case?

A. The Commission agreed with the Administrative Law Judge in the Company's last general rate case that "that the RUD-OAG had identified specific expenditures—for example, restaurant and catered meals, gift cards, floral arrangements, travel for employees' family members – that clearly should not be charged to ratepayers." [105] The Commission ordered the disallowance of the entire amount of employee recognition expenses, including gift cards, but allowed recovery of expenses related to employee safety incentives.

Q. Which Minnesota statutes did the Commission cite in its decision?

A. There were three statutes used to determine the disallowance of this expense, the first being Minnesota Statutes section 216B.03,[106] Minnesota Statutes section 216B.16, subdivision 4,[107] and Minnesota Statutes section 216B.16, subd. 4, that the utility has the burden of proof to prove the reasonableness of all Test Year expenses with any doubt as to its reasonableness being resolved in favor of the consumer, and that any travel, entertainment, or related employee expenses may only be allowed as a Test Year expense if it is necessary for the provision of utility service.

Q. Does the Company state that employee gifts are permitted for recovery?

A. Yes. The Company states "the statute permits recovery of reasonable gift expenses" and that "concern that such expenses must support the provision of utility service, limited

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[105] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 32-33 (Nov. 2, 2010).
[106] *Id.*
[107] *Id.*

years-of-service and retirement awards serve customers and the efficient provision of utility service by supporting employee retention and recognizing longevity of employee service."[108]

Q. How do you respond to this?

A. While the Company may state that these employee gifts are determined using established internal Human Resources procedures and are considered a non-discretionary expense, and while the Company may claim its service awards and retirement awards are required for employee retention for the provision of utility service, it is evident from information the Company has provided that the spending level for employee gifts has significantly fluctuated from year to year,[109] and that the Company claims that its voluntary terminations have increased over the 2010 to 2015 time period.[110] The evidence is inconsistent with the Company's claims and should not be used to justify expenses that have been previously found by the Commission to be unnecessary for the provision of utility service.

Q. What is your recommendation?

A. I recommend that the entire amount of employee gifts, including all gift cards, be removed from the 2017 Test Year. I request that the Company reconcile the differences between the various amounts it has provided in its Information Request responses, provide the correct actual cost amount from 2012 through 2016 for all categories that it has used in its responses, and provide the 2017 Test Year amount for these same categories.

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[108] *See* MPUC Information Request 3, Schedule SL-19.
[109] *See supra* Table 4 at 59.
[110] Johnson Direct at 7.

XIII. TRAVEL, ENTERTAINMENT, AND EMPLOYEE EXPENSES

Q. Is the Company requesting to recover expenses for travel, entertainment and employee expenses ("T&E")?

A. Yes. The Company has a 2017 T&E budget of approximately $4,907,032 to cover travel and Board compensation, in addition to $1,525,233 for membership dues and gifts for recovery in this case.[111] The Company has made a downward adjustment of $1,523,277 for travel and Board compensation, in addition to a downward adjustment of $97,014 to decrease the total amount of T&E expenses in the 2017 Test Year. The table below provides a summary of the request.

TABLE 7

Travel, Entertainment, and Employee Expenses

	2017 Budget (per DOC IR 115)		**2017 Adjustment (per OAG IR 315)**		**2017 Test Year Net of Adj**	
Travel and Lodging	$	1,941,497	$	(495,679)	$	1,445,818
Food and Beverage	$	677,413	$	(232,881)	$	444,532
Board Expenses and Compensation	$	891,791	$	(60,341)	$	831,450
Expenses of Ten Highest Paid Employees	$	265,161	$	(31,984)	$	233,177
Recreation and Entertainment	$	(99)	$	-	$	(99)
Corporate Aircraft	$	385,851	$	(385,851)	$	-
Registration/Fees/Parking/Other	$	745,418	$	(79,347)	$	666,071
Lobbying	$	-	$	(237,194)	$	(237,194)
Subtotal, excluding Dues and Gifts	**$**	**4,907,032**	**$**	**(1,523,277)**	**$**	**3,383,755**
Dues	$	1,422,726	$	(17,514)	$	1,405,212
Gifts	$	102,507	$	(79,500)	$	23,007
Total	**$**	**6,432,265**	**$**	**(1,620,291)**	**$**	**4,811,974**

* Investor Relations added to Travel and Lodging category for 2017 Adjustment column

[111] *See* Department Information Request 115, Schedule SL-20.

Q. Are there statutory and other requirements the Company is required to follow to support its recovery of T&E expenses?

A. Yes. The Legislature passed a law that is codified in Minnesota Statutes section 216B.16, subdivision 17 which was added to the rate case filing requirements in 2010. This requirement broadly expanded the filing requirements to support recovery of T&E expenses. These are the same requirements that the Commission ordered the Company to follow in its last general rate case due to "substantial doubt that it is reasonable, prudent, and necessary for the provision of utility service for Minnesota Power to spend $1,841,000 on an annual basis for Board and employee expenses."[112]

Q. What are the more significant aspects of the statutory T&E filing requirements?

A. The general requirement for allowing any cost recovery by a utility is that costs must be reasonable and necessary for the provision of utility service. Minnesota Statutes section 216B.16, subdivision 17 specifically prohibits the Commission from allowing recovery of any T&E expenses that are unreasonable and unnecessary. The statute includes the following filing requirements:

- separate itemization of nine specific categories of expenses including travel and lodging, food and beverages, recreational and entertainment, gift, and lobbying expenses;
- the itemization must identify the expenses in the most recently completed fiscal year and include the date of the expense, the vendor name, and the business purpose of the expense;

[112] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 32 (Nov. 2, 2010).

- for travel and lodging and food and beverage expenses the total amount for each category must be disclosed and separate itemization is required for these expenses for or on behalf of any employee at the level of vice-president or above and all board members; and
- the data is public data with limited exceptions regarding salaries for certain officers and employees.

Q. How has the Company reported its T&E expenses?

A. The Company has conducted a review of its actual T&E expenses from 2015, in order to create schedules itemizing these expenses to comply with the statute.[113] The Company has created "cost types" in its accounting system and a Chart of Accounts to track T&E expenditures by the expense categories required by the statute.[114] The Company has also reviewed its actual 2015 T&E expenditures to remove transactions that the Company deemed as having a vague business purposes, or were not necessary for the provision of utility service.[115]

Q. Which expense categories are you including in your T&E analysis and discussion?

A. I discuss my concerns and recommendations for all the expense categories defined in Minnesota Statutes section 216B.16, subdivision 17, except for membership dues and gifts, as the budget and transactions for these two cost categories are discussed separately above in Sections XI and XII.

[113] Morris Direct at 41.
[114] *See* OAG Information Request 312, Schedule SL-21.
[115] Morris Direct at 45–47.

Q. What are your concerns regarding the Company's T&E budget for the 2017 Test Year?

A. I have five concerns regarding the methodology the Company used to calculate the T&E amount for the Test Year. First, the Company's 2017 budget for T&E, which serves as the basis for the 2017 Test Year amount, is significantly greater than what the Company has spent in previous years. Second, the Company does not properly apply the T&E adjustment, which it has identified as expenditures that should not be recovered from ratepayers, to the 2017 budget. Third, there are a few expense transactions that are not required for the provision of utility service and do not benefit Minnesota ratepayers and should not be recovered. These costs should be included in the T&E adjustment to decrease the 2017 Test Year amount. Fourth, there are some transactions listing Minnesota Power as the credit card merchant, and it is not clear if the Company is charging ratepayers for expenses classified as "employee expense" that may also have already been included in the Test Year as "operating and maintenance expenses." Finally, while the Company has provided sufficient detail for most of its T&E expenses, there are a few expense transactions do not include all of the information that is required by law which I recommend the Company provide this information in the current rate case, as well as for any future rate cases.

Q. What is the Company's 2017 Budget for T&E expenses?

A. The Company has indicated its 2017 budget for T&E expenses, excluding membership dues and gifts, to be $4,907,032.[116] This budget is significantly higher than the actual

[116] *See* Department Information Request 115, Schedule SL-20.

expenditures the Company incurred for T&E expenses in the previous two years, as shown in the table below.

TABLE 8			
Travel, Entertainment, and Employee Expenses			
	2015 Actual (per DOC IR 115)	**2016 Actual (per OAG IR 131)**	**2017 Budget (per DOC IR 115)**
Travel and Lodging	$ 1,606,403	$ 1,651,194	$ 1,941,497
Food and Beverage	$ 542,107	$ 618,953	$ 677,413
Board Expenses and Compensation	$ 1,040,184	$ 1,070,118	$ 891,791
Expenses of Ten Highest Paid Employees	$ 192,228	$ 127,434	$ 265,161
Recreation and Entertainment	$ (183)	$ (242)	$ (99)
Corporate Aircraft	$ 425,908	$ 295,268	$ 385,851
Registration/Fees/Parking/Other	$ 418,280	$ 459,632	$ 745,418
Lobbying	$ -	$ -	$ -
Total, excluding Dues and Gifts	**$ 4,224,927**	**$ 4,222,357**	**$ 4,907,032**
% Increase over Previous Year			**16.2%**

Q. Is there a method that can be used to determine the reasonableness of the 2017 budget for T&E expenses?

A. Yes. Calculating a historical average of the actual expenditures for certain types of operating and maintenance expenses that do not reflect large capital expenditures would be appropriate for determining whether the 2017 budget is consistent with previous years.

Q. Do you recommend calculating a historical average to help determine whether the T&E budget is reasonable?

A. Yes. I calculated the historical average for T&E expenses for the three-year period from 2014 to 2016 to help determine the reasonableness of the 2017 budget. The most recent three-year period minimizes potential outlier data and captures the most recent spending for T&E expenses (2016), including one year in which the Company reduced employee expenses as a cost-saving measure (2015) as well as one year in which the Company

significantly increased employee expense spending (2014).[117] The table below shows the actual T&E expenditures for this time period and the three-year average that should be the amount in the 2017 Test Year for T&E expenditures, excluding dues and gifts.

TABLE 9						
Travel, Entertainment, and Employee Expenses						
	2014 Actual (per DOC IR 115)		**2015 Actual (per DOC IR 115)**		**2016 Actual (per OAG IR 131)**	
Travel and Lodging	$	2,178,372	$	1,606,403	$	1,651,194
Food and Beverage	$	679,495	$	542,107	$	618,953
Board Expenses and Compensation	$	1,077,193	$	1,040,184	$	1,070,118
Expenses of Ten Highest Paid Employees	$	286,466	$	192,228	$	127,434
Recreation and Entertainment	$	(236)	$	(183)	$	(242)
Corporate Aircraft	$	506,306	$	425,908	$	295,268
Registration/Fees/Parking/Other	$	715,577	$	418,280	$	459,632
Lobbying	$	-	$	-	$	-
Total, excluding Dues and Gifts	**$**	**5,443,173**	**$**	**4,224,927**	**$**	**4,222,357**
Three-Year Average					**$**	**4,630,152**

Q. Are there other factors that must be considered for calculating the three-year average for the Test Year?

A. Yes. I previously mentioned my concern regarding the Company improperly applying its T&E adjustment to the 2017 budget. The Company has proposed a downward adjustment of $1,523,277 to reduce the 2017 T&E budget.[118] This adjustment reflects the T&E expenses from 2015 that the Company deems is not necessary for the provision of utility service, and is representative of those types of expenses that should be excluded in the Test Year and should not be recoverable from ratepayers. This adjustment proposed by the Company should be factored into the calculation of the historical average, so that an accurate level of expenditures that are appropriate for recovery is reflected in the 2017 Test Year.

[117] *See* OAG Information Request 315, Schedule SL-22.
[118] $1,620,291 total adjustment less $97,014 adjustment for Dues and Gifts

Q. How does the Company currently treat this adjustment amount?

A. The Company reduces its 2017 T&E budget by the adjustment amount in order to calculate the 2017 Test Year amount.

Q. Does the Company have more than one adjustment amount based on 2015 actual T&E transactions?

A. Yes. The Company has identified that there are 2015 T&E transactions totaling $1,767,936 that are unrecoverable.[119] In applying this adjustment to the 2017 T&E budget, however, the Company substitutes the identified 2015 amounts for the "Board Expenses," "Corporate Aircraft," and "Investor Relations" cost categories with the 2017 budget for these categories. Therefore, although it identified transactions totaling $1,767,936 that are inappropriate for recovery, it is only adjusting the 2017 T&E budget by $1,620,291.

Q. Is the Company's proposed application of the adjustment to the Test Year and the substitute of identified unrecoverable transactions reasonable?

A. No. The adjustment should be applied to the year in which the transactions were incurred, and the identified actual 2015 transactions should not be randomly substituted with a budget amount for that cost category. As I explain below, the methodology for calculating the 2017 Test Year amount should be based on a three-year average.

Q. Are you recommending that the Company incorporate this adjustment amount a different way?

A. Yes. Rather than reducing the 2017 T&E budget by the amount of individual expenses from a previous year (2015) that it believes are not recoverable, the Company should

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[119] *See* OAG Information Request 315, Schedule SL-22.

reduce the previous year's total amount of actual T&E expenses by the amount of individual expenses that it has identified as not being recoverable. The result would be the correct amount of T&E expenditures that should be recovered from ratepayers. This adjusted actual level of T&E expenses for the previous year would then be used to calculate the three-year historical average.

Q. Would this historical average serve as the 2017 Test Year budget?

A. Yes. Rather than using the Company's current methodology of reducing its 2017 T&E budget by the transactions that it deems as not recoverable from a previous fiscal year, it is more reasonable to use a historical average that normalizes the level of employee expenses. Incorporating the adjustment in the calculation of the historical average would more accurately reflect the T&E amount that should be recovered from ratepayers in the Test Year.

Q. Does this new method impact the way the Company prepares for a rate case?

A. No, it does not impact the Company's preparation for rate cases. The Company would still provide T&E schedules for the most recently completed fiscal year to comply with the statute and the Company would use the same method it currently does to identify unrecoverable transactions, but the way the Company applies the adjustment to the Test Year would be different. Instead of just taking the adjustment off the top, the Company would incorporate the adjustment into the calculation of a historical average.

Q. Has the Company identified T&E transactions that are unrecoverable for the years 2014 and 2016?

A. No. The Company has only created T&E schedules for transactions in 2015 as a filing requirement. The Company has not created T&E schedules for 2014 or 2016.

Q. How should the adjustment amount be determined for 2014 and 2016?

A. Since the Company does not have transactional level data for these years, I used the ratio of identified expenses from 2015 to calculate a representative amount that should be excluded from the actual expenses in 2014 and 2016.

Q. Is this approach reasonable?

A. Yes. This approach is reasonable because the types of T&E expenses have remained consistent during this time period. In addition, there have been no significant changes to the Company's employee expense policies, or the Company's T&E allocations that would impact the level of employee expenses.

Q. Provide the calculation of the 2014 and 2016 adjustment amounts.

A. The identified T&E expenses, excluding dues and gifts from 2015, is $1,670,922.[120] It is unclear, however, whether the Company has included the T&E expenses for the "Lobbying" category in the 2015 actual expenses provided in its response to the Department's Information Request 115. Therefore, in my current calculation of the 2015 ratio, I removed the adjustment of $237,194 for the "Lobbying" category from the adjustment amount of $1,670,922. The ratio of the adjustment of $1,433,728 is approximately 34% of the 2015 actual T&E expenses of $4,224,927, excluding dues, gifts, and lobbying. Applying this ratio to the actual T&E expenses of $5,443,173 in

[120] *See* OAG Information Request 315, Adjustments to 2015 Actuals, Schedule SL-22.

2014 results in an adjustment of $1,850,679 for 2014.[121] Applying this ratio to the actual T&E expenses of $4,222,357 in 2016 results in an adjustment of $1,435,601 for 2016.[122]

Q. What is the three-year average for T&E expenses using these adjusted actual amounts?

A. The three-year average is $3,056,816, which is $509,331 less than the Company's current request of $3,566,147 as shown in the table below.

TABLE 10

Travel, Entertainment, and Employee Expenses

	2014 Actual (per DOC IR 115)	**2015 Actual (per DOC IR 115)**	**2016 Actual (per OAG IR 131)**	**2017 Test Year Net of Adj (per OAG IR 315)**
Travel and Lodging	$ 2,178,372	$ 1,606,403	$ 1,651,194	$ 1,367,771
Food and Beverage	$ 679,495	$ 542,107	$ 618,953	$ 423,544
Board Expenses and Compensation	$ 1,077,193	$ 1,040,184	$ 1,070,118	$ 891,791
Expenses of Ten Highest Paid Employees	$ 286,466	$ 192,228	$ 127,434	$ 221,659
Recreation and Entertainment	$ (236)	$ (183)	$ (242)	$ -
Corporate Aircraft	$ 506,306	$ 425,908	$ 295,268	$ -
Registration/Fees/Parking/Other	$ 715,577	$ 418,280	$ 459,632	$ 661,382
Lobbying	$ -	$ -	$ -	$ (237,194)
Total, excluding Dues and Gifts	**$ 5,443,173**	**$ 4,224,927**	**$ 4,222,357**	**$ 3,328,953**
Adjustment, excluding Lobbying	**$ (1,850,679)**	**$ (1,433,728)**	**$ (1,435,601)**	**$ 237,194**
Adjusted Total	**$ 3,592,494**	**$ 2,791,199**	**$ 2,786,756**	**$ 3,566,147**
Three-Year Average			**$ 3,056,816**	

* Investor Relations added to Travel and Lodging category for 2017 Test Year Net of Adjustment column

Q. Is your calculation based on accurate T&E expense amounts?

A. The Company has provided a variety of T&E schedules and has provided T&E budget, actual, and adjustment amounts for the various cost categories for the different periods between 2011 and 2017 in its responses to Information Requests. However, it appears that amounts provided in one report may be different from amounts provided in another report for the same year.[123] While I tried to cross reference the amounts between

[121] ($5,443,173) * 34%
[122] ($4,222,357) * 34%
[123] 2017 Test Year and 2015 Actual amounts in Department Information Request 115 different from 2017 Test Year and 2015 Actual amounts in OAG Information Request 315.

different Company provided reports and schedules, I was not able to reconcile the differences. I assume that this is because the budget, actual, and adjustment amounts provided in the various reports may not be inclusive of all of the T&E cost categories. Therefore, I request that the Company explain any variances between the T&E budget, actual, and adjustment amounts shown in its responses to the Department's Information Request 115 and OAG Information Request 131 and 315, and provide the T&E budget, actual, and adjustment amounts for all cost categories shown below for each year from 2014 to 2017.

- Travel and Lodging – Employee
- Travel and Lodging – VP/Ten Highest Paid
- Food and Beverage – Employee
- Food and Beverage – VP/Ten Highest Paid
- Board of Director Expenses and Compensation
- Expenses of VP/Ten Highest Paid
- Recreation and Entertainment
- Dues and Expenses
- Gifts
- Corporate Aircraft
- Lobbying
- Registration/Fees/Parking/Other
- Investor Relations

Q. Will the three-year average amount change as a result of this information that will be provided by the Company?

A. Pending the Company's clarification of the budget, actual, and adjustment variances between the reports, the three-year average amount I calculated above would change if the T&E budget, actual, and adjustment amounts are different than the ones I relied on.

Q. What are your concerns about additional T&E expenses from 2015 that should be included in the T&E adjustment identified by the Company?

A. In reviewing the actual T&E transactions from 2015, I found a few transactions that pertain to costs incurred in other states for the benefit of employees to practice in other states. Since these costs are not required for the provision of utility service and do not benefit Minnesota ratepayers, they should be disallowed. These transactions total $632 and are listed in Schedule SL-23 under the header "Transactions from Schedule I – 5B All Other – VP - TT." One transaction included in this listing is for the Nebraska State Bar Association and it is unclear if this transaction is the same one that has been included in the "membership dues" category in Section XI above.

Q. What are your concerns about the transactions that list Minnesota Power as the credit card merchant?

A. There are transactions listing Minnesota Power as the vendor and it is unclear why the Company is listed as the vendor. I would be concerned if the Company was double counting these expenses by recovering these costs under the "employee expense" cost category in the Test Year, in addition to recovering these costs as normal operating and maintenance expenses under a different expense category in the Test Year. These

transactions total $6,301 and are listed in Schedule SL-23 under the header "Transactions that List Minnesota Power as Pcard Merchant."

Q. What is your recommendation for these transactions?

A. I request that the Company clarify why it is listed as the credit card merchant and whether these costs have also been included under another operating and maintenance expense category in the Test Year. The Company should confirm that it has not double counted this expense for recovery in the Test Year. If the costs are double counted, then a correcting adjustment should be made by increasing the 2015 T&E adjustment amount to decrease the 2017 Test Year amount.

Q. What are the transactions that have insufficient details?

A. I found that there were some transactions that did not include all of the information required by law, specifically the absence of the vendor name. These transactions total $27,520 and are listed in the attached Schedule SL-23 under the header "Transactions Without Vendor Name." These transactions do not have a vendor name, other than the name of the Minnesota Power employee. Minnesota Statutes section 216B.16, subdivision 17 specifically requires that utilities provide the vendor name of each expense they seek to recover from ratepayers. The OAG requested the vendor or merchant name for these transactions, but were told that these were Minnesota Power employee reimbursements for expenses they already incurred and because the Company did not pay the businesses directly, the Company would not be able to provide the business names.[124]

[124] *See* OAG Information Request 313, Schedule SL-24.

Q. What other information should be provided for these transactions?

A. For most of the T&E transactions, the Company was able to provide either the Pcard Merchant, Hotel Accommodation, Restaurant Name, Vendor Name, or identify the transactions that were for mileage reimbursements.[125] Since the Company would have required the employee requesting the reimbursement to substantiate the request with original receipts and other documentation, the Company should easily be able to provide the vendor name. Additionally, the Company should provide the subaccount, subaccount title, cost type, and cost type title that each transaction is coded to. This subaccount, subaccount title, cost type, and cost type title appears to be information requirements that an employee must enter for employee expense reports and credit card reconciliations through the Company's Oracle iExpense system.[126]

Q. What is your recommendation for these transactions?

A. I request that the Company provide the vendor names for these transactions. It appears the Company was able to determine this information for all the other transactions using either the employee reimbursement requests or the subaccount/cost types the transactions were coded to because the Company provided the hotel name, restaurant name, as well as identifying mileage reimbursement transactions. Further, I request that the Commission order the Company to provide this information in its next rate case to assist in the review of T&E expenses.

Q. Are the 2015 transactions in the T&E schedules incorporated into the Test Year?

A. The 2015 transactions in the T&E schedules are not directly incorporated into the Test Year. These 2015 T&E expenses are provided at the transactional detail level in order to

[125] *See* OAG Information Request 132, Schedule SL-25.
[126] MP Exhibit_(SWM) Schedule 10.

comply with Minnesota Statutes § 216B.16, subd. 17. However, the Company reviewed all actual 2015 T&E expenses and identified $1,767,936 of transactions that are inappropriate for recovery, and reduced the 2017 Test Year amount by that amount. Therefore, any additional transactions identified in the 2015 T&E schedules as being not recoverable from ratepayers would increase the Company's adjustment and further decrease the 2017 Test Year amount.

Q. How will any 2015 actual transactions that you recommend disallowance for be incorporated into the 2017 Test Year?

A. The transactions that I recommend disallowance for should be added to the $1,767,936 adjustment identified by the Company, to further reduce the 2015 actual employee expenses that are recoverable, which is then used to calculate of the three-year average.

Q. How would this methodology lead to a more reasonable level of employee expenses that ratepayers should pay for?

A. For ratemaking purposes, reducing the actual employee expenses to account for transactions that are not recoverable is the most accurate way to determine the 2017 Test Year amount. This adjusted actual level of employee expenses can be used to calculate the three-year average for the 2017 Test Year, and would reflect a normalized level of T&E expense.

Q. What is your recommendation?

A. I recommend that $632 associated with expenses that are not required for the provision of utility service be disallowed for recovery at this time. Since I have requested additional information from the Company regarding the other transactions, I will include my recommendation for those transactions in rebuttal testimony. The $632 amount will

increase the 2015 adjustment to $1,434,360 and be used to calculate the three-year average of $ 3,056,606 which will serve as the T&E amount in the 2017 Test Year. The table below shows the new calculation.

TABLE 11
Travel, Entertainment, and Employee Expenses after OAG Adjustment

	2014 Actual (per DOC IR 115)	2015 Actual (per DOC IR 115)	2016 Actual (per OAG IR 131)	2017 Test Year Net of Adj (per OAG IR 315)
Travel and Lodging	$ 2,178,372	$ 1,606,403	$ 1,651,194	$ 1,367,771
Food and Beverage	$ 679,495	$ 542,107	$ 618,953	$ 423,544
Board Expenses and Compensation	$ 1,077,193	$ 1,040,184	$ 1,070,118	$ 891,791
Expenses of Ten Highest Paid Employees	$ 286,466	$ 192,228	$ 127,434	$ 221,659
Recreation and Entertainment	$ (236)	$ (183)	$ (242)	$ -
Corporate Aircraft	$ 506,306	$ 425,908	$ 295,268	$ -
Registration/Fees/Parking/Other	$ 715,577	$ 418,280	$ 459,632	$ 661,382
Lobbying	$ -	$ -	$ -	$ (237,194)
Total, excluding Dues and Gifts	**$ 5,443,173**	**$ 4,224,927**	**$ 4,222,357**	**$ 3,328,953**
Adjustment, excluding Lobbying	**$ (1,850,679)**	**$ (1,433,728)**	**$ (1,435,601)**	**$ 237,194**
Adjustment, per OAG		**$ (632)**		
Adjusted Total	**$ 3,592,494**	**$ 2,790,567**	**$ 2,786,756**	**$ 3,566,147**
Three-Year Average			**$ 3,056,606**	

* Investor Relations added to Travel and Lodging category for 2017 Test Year Net of Adjustment column

XIV. SUMMARY AND CONCLUSION

Q. Can you summarize your recommendations?

A. Yes. I recommend the following specific reductions to the revenue requirement:

- $1,604,396 for transmission capital projects;
- $732,272 for storm damage amortization expense;
- $275,745 for the Sappi/Cloquet amortization expense;
- $350,000 for credit card processing fees;
- $99,068 for charitable contributions.

The total impact of these adjustments is a reduction to the revenue requirement of $3,061,481.

I also recommend reductions to the revenue requirement related to transmission capital impacts on 2017 projects, generation capital projects, membership dues, employee

gifts, and travel and entertainment expenses, but do not have the information to calculate the impact of these adjustments at this time. I will provide an update in my rebuttal testimony.

In addition, I recommend that the Commission reject MP's proposal related to BEC 3 and 4, which has the impact of increasing the revenue requirement by $15,936,118. At this time, I note that Minnesota Statutes section 216B.16, subdivision 5 provides that "[i]n no event shall the rates [set in a rate case] exceed the level of rates requested by the public utility." While I am not an attorney and I understand that the OAG may provide further analysis on this section in its legal briefing, the plain meaning of these words indicates that the final rates set in this proceeding, even when adjusted to account for decisions related to the BEC units, cannot exceed the amount of revenue requested by MP in its petition.

Q. Does this conclude your testimony?

A. Yes.